A STUDY ON VARIATIONS IN INDUSTRIAL ELECTRICITY TARIFF & REGULATORY INTERVENTION IN KERALA STATE

Thesis Submitted in Partial Fulfillment of the Requirements for the Award of the Degree of Doctor of Philosophy in Applied Economics

By

V.SREEKUMAR

Reg. No. 3250

Under the Guidance of

Dr. M. MEERA BAI

DEPARTMENT OF APPLIED ECONOMICS

COCHIN UNIVERSITY OF SCIENCE AND TECHNOLOGY

KOCHI-682 022

SEPTEMBER-2011

DEPARTMENT OF APPLIED ECONOMICS
COCHIN UNIVERSITY OF SCIENCE AND TECHNOLOGY
KOCHI-682 022, KERALA, S. INDIA

Phone: 0484:2556030
Fax: 0484:532495

No. AE

Date:…………………..

CERTIFICATE

I certify that the work entitled, **"A STUDY ON VARIATIONS IN INDUSTRIAL ELECTRICITY TARIFF AND REGULATORY INTERVENTION IN KERALA STATE"** *is a bonafide research work done by* **Sri. V. SREEKUMAR** *in partial fulfillment of the requirements for the award of the degree of* ***Doctor of Philosophy*** *in the* ***Department of Applied Economics, Cochin University of Science and Technology, Kochi-22*** *under my supervision and guidance. This thesis has not been the basis of the award of any degree, diploma, fellowship or other similar titles of recognition. The thesis is the outcome of personal research work done by the candidate under my overall supervision.*

Dr. M.MEERA BAI

DECLARATION

I hereby declare that the thesis entitled **"A STUDY ON VARIATIONS IN INDUSTRIAL ELECTRICITY TARIFF AND REGULATORY INTERVENTION IN KERALA STATE"** *is the record of bonafide research carried out by me under the supervision of* **Dr. M. MEERA BAI, Head, Department of Applied Economics, Cochin University of Science and Technology** *in partial fulfillment of the requirements for the award of the degree of* ***Doctor of Philosophy*** *in the* ***Department of Applied Economics, Cochin University of Science and Technology, Kochi-22.*** *I further declare that this has not been the basis of the award of any degree, diploma, fellowship or other similar titles of recognition.*

V.SREEKUMAR

Kochi-22

Date:…………........

Dedicated to

My Beloved Father,

Sri. P. K.Vasudeva

Kurup.

ACKNOWLEDGEMENT

At the very outset, I have great pleasure to express my heartfelt gratitude to my supervisor and guide Dr. M.Meera Bai, Head of the Department, Department of Applied Economics, Cochin University of Science and Technology. The motivation given by her alone helped me to start and proceed on the work. In spite of her busy schedule, she was ready to help me always by sparing a lot of her valuable time to me for this work. I sincerely acknowledge all help and guidance extended to me and my gratitude to her is beyond expressing by words.

My thanks are due to Dr. P.Arunachalam, Prof. (Dr.) D. Rajasenan, Prof. (Dr.) S. Harikumar and Dr. P. K. Manoj for their valuable suggestions. I would like to thank the Office Staff and Sri. K. Balachandran, Librarian, Department of Applied Economics, for their timely help.

My sincere thanks are also due to Dr. K. C. Sankaranarayanan, Director Management Studies, M.E.S College Marambilly; Dr. P.R. Poduval, Retired Director, School of Management Studies; Dr. M.Bhasi, Dean, School of Management Studies; Dr. D. Mavooth, Faculty Member, School of Management Studies; Sri.M.K.G.Pillai, Former Chairman, Kerala State Electricity Regulatory Commission, for having sharpened many of my observations.

No word can express my gratitude to Sri. C .G. Jolly, Senior Vice President (Retired), Hindalco Industries Limited, Kalamassery, who has given me an opportunity to work for the electricity related matters of Hindalco Industries Limited and constantly encouraged me to acquire more and more knowledge on power sector.

My since thanks are also due to Dr. B. Jayashankar, Senior Economic Analyst, Kerala State Electricity Regulatory Commission, Sri. George Thomas, President, Kerala HT&EHT Industrial Electricity Consumers Association;

Sri. A.R. Satheesh, General Manager, Carborundum Universal Limited; Sri. A. M. Muhammed Nawas, Vice President, Binani Zinc Limited; Sri.K.K.George, Secretary, Kerala HT& EHT Industrial Electricity Consumers Association for giving me necessary insight and direction in getting the required data for my research work.

It is a privilege to express my sincere and deep gratitude to Sri.N.Peethambara Kurup, MP (Kollam), Sri.P.K.Kumara Kurup, Social Activist and former President of Co-Operative Urban Bank Ltd, Cherthala, Sri.K.Chandran Pillai, Ex MP(Rajya Sabha), Sri. C.M. Dinesh Mani, Ex. MLA and Syndicate Member, CUSAT, Sri. N.K.Vasudevan, Syndicate Member, CUSAT, Sri. A. M. Yusaf, Ex. MLA, Dr. A. B. Aliyar, Administrative Officer, United India Insurance Company Limited, who inspired me by giving timely advice and instructions.

I also owe a deep debt of gratitude to my present as well as retired colleagues in Hindalco Industries Limited, Mr.D.Bhattacharya (M.D,Hindalco), Mr.R.S.Dhulkhed, Mr.N.Mohan (Retd.),Dr.E.C.Jose (Retd.), Mr. B. J. Alexander, Mr.K.Kumaravel, Mr. P. C. Bhasuran (Retd.), Mr.C.K.Krishnan, Mr.J.Haridas, Mr. K. V. Prabhakaran, Mr.K. G. Vinod Kumar and all my well wishers in Hindalco (Indal) family who constantly encouraged me for the completion of this research work.

Finally, I wish to thank my mother Smt. G. Bhanumathy Amma, my father-in-law Sri V.Damodaran Pillai and my mother in law Smt.K.Ammini Amma, for their prayers and blessings. I also thank my wife Anitha, my son Sooryanarayan, my daughter Vyshnavi, my sister Umadevi and my brother Raveendranadh and all other family members whose support goes beyond my academic domain. It is because of them that I am able to achieve my goal of finishing the thesis.

V.SREEKUMAR

CONTENTS

Chapter – 7 A CASE OF POWER TARIFF HIKE WITH RESPECT TO A POWER INTENSIVE CONSUMER IN KERALA

Chapter – 8 THE IMPACT OF REGULATORY REGIME IN KERALA

LIST OF TABLES

LIST OF FIGURES

CHAPTER-1

INTRODUCTION

Electricity is the prime mover of a modern society. It is regarded as the lifeblood of economic activities. Electricity is an essential requirement for all facets of our life. It has been recognized as a basic human need. It is a critical infrastructure on which the socio-economic development of the country depends. Supply of electricity at reasonable rate to rural India is essential for its overall development. In the first hundred years of its commercialization, electricity was supplied to consumers by vertically integrated monopolies. It was generally felt that this was the only feasible option due to complexity as commodity and its natural monopoly aspects.

It is one of the major infrastructural facilities required for setting up manufacturing industries in the country. Generation of electricity in Kerala was mainly focused on hydroelectric potential, started with the installation of Pallivasal hydroelectric project by the Maharajah of erstwhile Travancore State in the year 1939. Electricity was comparatively very cheap and a number of major Industries were attracted to the state of Travancore in 1940s and to the State of Kerala in the subsequent decades. After the successful commissioning of Pallivasal Hydroelectric Project, a number of major hydroelectric schemes were executed in the State including Idukki (760 MW) and Sabarigiri (320 MW). The pace of development of hydroelectric power projects was slowed down due to environmental and other sociopolitical considerations. As a result, the state of Kerala was compelled to set up thermal power stations and to depend on central share from central generating stations (CGS), which are mainly coal based stations, to meet the demand and as a result the average cost of electricity/per unit in the state has increased considerably.

Kerala State is gifted by nature with two monsoons and other sporadic rains, having good yield of water from its 44 rivers with good number of streams and tributaries. The maximum rainfall occurring in the high ranges is 7620 mm and the average is 3065 mm. The annual water yield is not experiencing much variation. Out of 4000 MW of estimated hydroelectric power potential in the state, only 45 % has been tapped so far. In other words, vast potential for hydroelectric power generation schemes is available in the state for exploitation. The main natural resource that Kerala can depend for power generation is water, especially in the absence of other resources in the state for power generation. Water is replenished every year during the two monsoon periods. The quantity of rainfall occurring in a particular region is only experiencing slight variation annually. Therefore, the availability of water for power generation is fairly dependable. Since water is received from nature, generally no separate cost is considered for it as a raw material, when used for various purposes, including power generation. Therefore, the cost of energy generated from hydropower station is relatively very less. The repeated increases in cost of fuel at the places of production would result in the increase in cost of production of power every year. In India, the price of oil alone has become more than the double in the last decade.

Since the power generated from hydroelectric stations depend up on the head available, more power could be generated from same quantity of water in schemes having higher heads. So also, more quantity of water will be required for generating same quantity of power in low head schemes. The potential head of water available and its quantity are nature's gift. But in the case of fossil fuel based stations the quantum of energy that could be generated from a measure of fuel is limited and also depend on the quality of fuel (calorific value) and efficiency of equipment. Out of the ten numbers of major hydroelectric projects so far completed in Kerala, the Idamalayar Project, which has the lowest head of 110 metres, requires 4000 litres of water for generating one unit of energy, whereas Sabarigiri Project having a head of 750 metres requires only 620 Litres.

All rivers and their tributaries originate from high ranges on the eastern side of Kerala, flowing down to lower reaches and finally joins the sea. The same water could be repeatedly be utilised for power generation in all power stations formed along the course of the river by making use of the height difference of terrain at different locations. But in the case of fossil fuels, once when used for any purpose, they are lost forever.

The life span or serviceable period of structures and station equipment of hydel projects is very much longer than other types. The life expectancy of a hydel power station is 100 years whereas that of thermal station is only 25 to 30 years.

However, the growth of hydroelectric power sector in the state depicts a dismal picture mainly because of the problems associated with acquisition of forestland, rehabilitation of people and other environmental considerations and issues. However, in the context of global warming, development of non-polluting hydel projects attain paramount importance. The average cost of power generated from hydroelectric power plants is very less compared to thermal stations. Estimated variable cost of hydel power as projected by KSEB for 2010-11 was almost zero paise per unit (Refer table no. 8.27 – Merit order stack as projected by KSEB)

Affordability of Electricity Tariff is the one of most important factors, which decides the survival of industrial units, especially the power intensive ones. Electricity Tariff fixation in Kerala was done by State Government as per the proposal of Kerala State Electricity Board (KSEB). The Government seldom questioned the reasons for poor efficiency and the spiraling increase in the cost of KSEB before tariff approval. The tariff setting process has changed totally after the setting up of Kerala State Electricity Regulatory Commission (KSERC) in November 2002. Now, the efficiencies and costs of KSEB are subjected to close scrutiny by the commission as well as public as the tariff fixing process was made totally transparent as per the Electricity Act-2003. Arresting the steep increase in electricity tariff, which was in vogue for a decade, and maintaining it at the same level for almost another decade is the single largest achievement the regulatory regime (KSERC) in Kerala. It has prevented closure of several industries in the state. This is not a simple achievement when we compare the functioning of KSEB as a monopoly public sector utility in the past decades. But this is not properly realized and appreciated by the public and media. KSEB has now started to realize the power of KSERC, though belatedly. The pivotal theme of this research work is the impact of regulatory regime in Kerala's power sector.

1.1 Review of Indian Power Sector

1.1.1 Introduction

The electricity sector in India is predominantly controlled by the Government of India's public sector undertakings (PSUs). Major PSUs involved in the generation of electricity include National Thermal Power Corporation (NTPC), National Hydroelectric Power Corporation (NHPC) and Nuclear Power Corporation of India (NPCI). Besides PSUs, several state-level corporations, such as Maharashtra State Electricty board (MSEB), Kerala State Electicty Board (KSEB), Tamil Nadu State Electricity Board (TNEB), Gujarat State Electricity Board (four distribution Companies viz. MGVCL, PGVCL, DGVCL and UGVCL, one controlling body GUVNL, and one generation company GSEC) are also involved in the generation and intra-state distribution of electricity. The Power Grid Corporation of India limited (PGCIL) is responsible for the inter-state transmission of electricity and the development of national grid.

The Ministry of Power is the apex body responsible for the development of electrical energy in India. This ministry started functioning independently from 2 July 1992, earlier it was known as the Ministry of Energy.

India is world's 6th largest energy consumer, accounting for 3.4 % of global energy consumption. Due to India's economic rise, the demand for energy has grown at an average of 3.6% per annum over the past 30 years. In June 2010, the installed power generation capacity of India stood at 162,366 MW, while the per capita energy consumption stood at 612 kWh (Units). The country's annual energy production increased from about 190 billion units (kWh) in 1986 to more than 680 billion units (kWh) in 2006. The Indian government has set an ambitious target to add approximately 78,000 MW of installed generation capacity by 2012. The total demand for electricity in India is expected to cross 950,000 MW by 2030. About

70% of the electricity consumed in India is generated by thermal power plants, 21% by hydroelectric power plants and and 4% by nuclear power plants. More than 50 % of India's commercial energy demand is met through the country's vast coal reserves. The country has also invested heavily in the recent years on renewable sources of energy such as wind energy. As of 2008, India's installed wind power generation capacity stood at 9,655 MW. Additionally, India has committed massive amount of funds for the construction of various nuclear reactors which would generate at least 30,000 MW. In July 2009, India unveiled a $19 billion plan to produce 20,000 MW of solar power by 2020.

Electricity losses in India during transmission and distribution are extremely high and vary between 30 to 45%. In 2004-05, electricity demand outstripped supply by 7-11%. Due to shortage of electricity, power cuts are common throughout India and this has adversely affected the country's economic growth.Theft of electricity which is common in most parts of urban India, amounts to 1.5% of India's GDP. Despite an ambitious rural electrification program, some 400 million Indians lose electricity access during blackouts.While 80 percent of Indian villages have at least an electricity line, just 44 percent of rural households only have access to electricity. According to a sample of 97,882 households carried out in 2002, electricity was the main source of lighting for 53% of rural households compared to 36% in 1993. Multi Commodity Exchange has sought permission to offer electricity future markets.

1.1.2 Power Generation Details (June-2010)

Grand Total Installed Capacity is 1,62,366 MW (Figure 1.1 to 1.3 for details)

1.1.2.1 Thermal Power

- Current installed capacity of Thermal Power as of June 2010 is 1,04,424 MW which is 64 % of total installed capacity.
- Current installed base of Coal Based Thermal Power is 86003 MW which comes to 53% of total installed base.
- Current installed base of Gas Based Thermal Power is 17,221 MW which is 10.61% of total installed base.

- Current installed base of Oil Based Thermal Power is 1,199.75 MW which is 0.74% of total installed base.
- The state of Maharashtra is the largest producer of thermal power in the country.

1.1.2.2 Hydro Power

India was one of the pioneering countries in establishing hydroelectric power plants. The power plants at Darjeeling and Shimsha (Shivanasamudra) were established in 1898 and 1902 respectively and are regarded as first hydel plants in Asia. The installed capacity as of 2008 was approximately 36877.76 MW**.** The public sector has a predominant share of 97% in Hydel Sector.

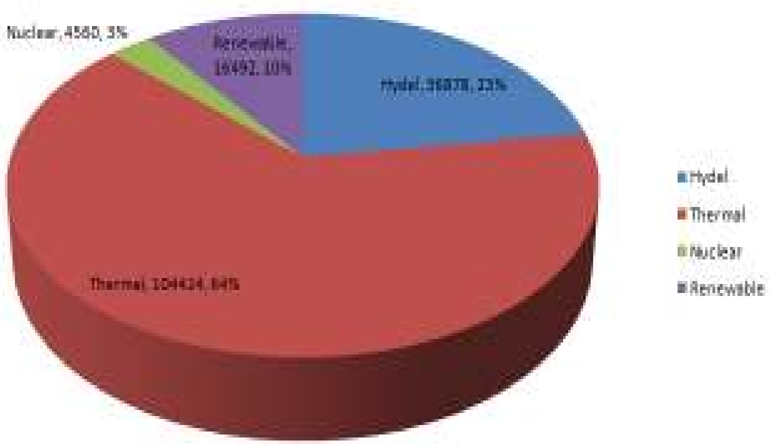
1.1.2.3 Nuclear Power

As of June 2010, seventeen nuclear power plants in India produce 4,560 MW (2.81% of total installed base) electricity. Nuclear power is the fourth largest source of electricity in India after thermal, hydro and renewable sources of electricity. By the end of 2011, the number of nuclear power plants in operation in the country would be twenty with a combined installed capacity of 4780 MW. The Centre had given a financial sanction of Rs 24,000 crore in October 2009 for building four units of 700 MW of PHWRs (Pressurised Heavy Water Reactors), two each at Kakrapar and Rawatbhata in Rajasthan and the construction is in progress. NPCIL is building two nos., 1000 MW nuclear power plants at Koodamkulam; first unit is expected to be commissioned by the end of 2011 followed by the second unit by middle of 2012. With the progressive completion of the Kudankulam reactors and the four 700 MW PHWRs at Kakrapar and Rawatbhata, the installed nuclear power capacity of NPCIL is expected to reach 9,580 MW by 2016. India is now involved in the development of fusion reactors through its participation in the ITER (International Thermonuclear Experimental Reactor) Project. Since early 1990s, Russia has been a major source of nuclear fuel to India. Due to dwindling domestic uranium reserves, electricity generation from nuclear power in India declined by 12.83 % from 2006 to 2008. Following a waiver from Nuclear Suppliers Group (NSG) in September 2008 which allowed the country to commence International Nuclear Trade, India has signed nuclear deals with several other countries including France, United States, United Kingdom, Canada, Namibia, Mongolia, Argentina, and Kazakhstan in February 2009. India has also signed a $700 million deal with Russia for the supply of 2000 tonnes of nuclear fuel. India has drawn up an ambitious plan to reach a nuclear power capacity of 63,000 MW in 2032 by setting up of 16 indigenous Pressurised Heavy Water Reactors (PHWR) each, including ten based on reprocessed uranium. India would export 220 MW, 540 MW and 700 MW, PHWRs by 2032. Beyond 2032, large capacity addition would be taken up by setting up metallic fuel FBRs and introduction of reactors based on thorium 232 and uranium 233 fuel cycle. Crrently, India was in a position for setting up its export model 220 MW PHWR in friendly countries

1.1.2.4 Renewable Power

Current installed base of Renewable Energy is **16,492 MW** which is 10.12% of total installed base with the southern state of Tamil nadu contributing nearly a third of it (5008.26 MW) largely through wind power.

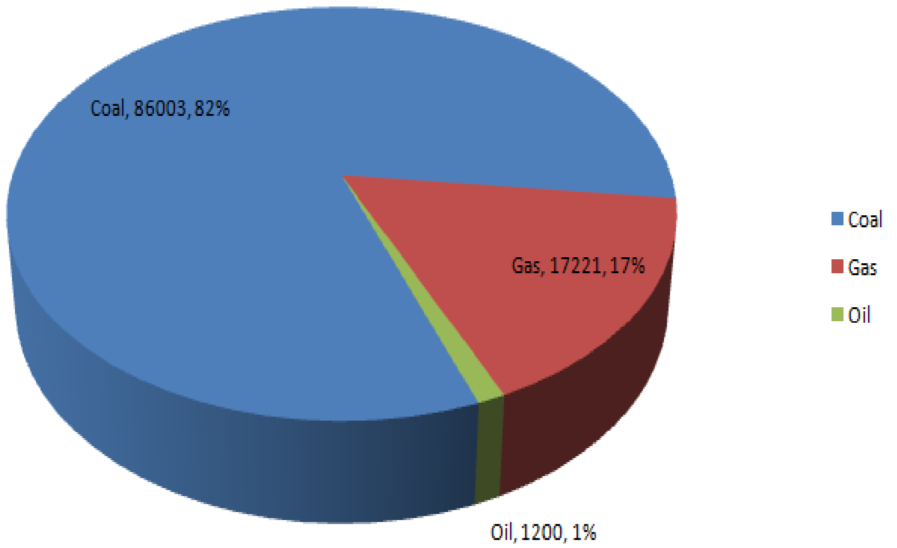
Figure No.1.1
Total installed capacity of power in India 162366 MW



Source: National Hydro Power Corporation, New Delhi

Figure 1.2

Thermal Power Generation in India -104424 MW



Source: National Hydro Power Corporation, New Delhi

Table 1.1

Plan-wise growth of generation capacity

Plan Period	Hydro Capacity Addition during the Plan (MW)	Installed Capacity at the end of Plan (MW)		
		Hydro Installed Capacity	Total Installed Capacity including other R.E.S.	Hydro Power share as % of total Installed Capacity
3rd Plan(1961-66)	1783.17	5906.91	12957.27	45.58
8th Plan (1992-97)	2427.65	21644.8	85019.31	25.46
9th Plan (1997-02)	4538.25	26261.23	103410.04	25.40
10th Plan (2002-07)	7886.00	34653.77	132329.21	26.19
11th Plan (2007-12) upto Nov.,2010	3921	37367.40*	167077.36	22.40

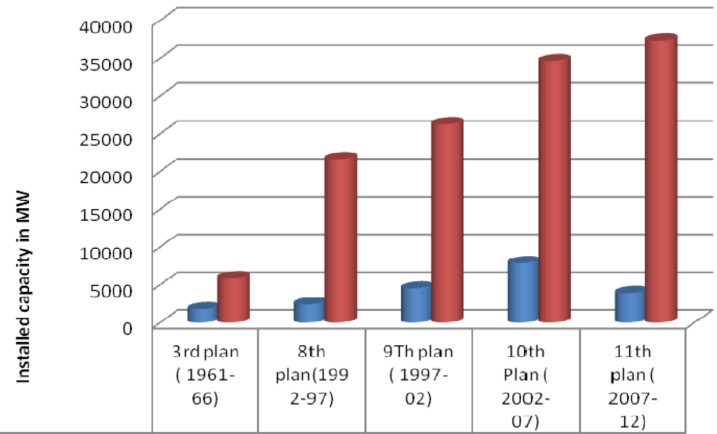
** Does not include hydro projects having capacity upto 25 MW The matters relating to hydro projects upto 25 MW are looked after by Ministry of New & Renewable Energy (MNRE).*

Hydro Capacity addition during these Plans has been less as compared to Thermal capacity addition.

Source: National Hydropower Development Corporation, New Delhi

Figure No.1.3

Planwise Growth of Hydro Power in India



	3rd plan (1961-66)	8th plan(1992-97)	9Th plan (1997-02)	10th Plan (2002-07)	11th plan (2007-12)
Hydro power addition during the plan (MW)	1783	2427	4538	7886	3921
Hydro installed capacity at the end of the plan	5906	21644	26261	34653	37367

Source: National Hydro Power Corporation, New Delhi

1.1.3 Transmission

Transmission of electricity is defined as the bulk transfer of power over a long distance at high voltage, generally of 132 kV and above. In India bulk transmission lines has increased from 3,708 ckm (circuit-kilometres) in 1950 to more than 165,000ckm today in 2010(as stated by Power Grid Corporation of India). The entire country has been divided into five regions for transmission systems, namely, Northern Region, North Eastern Region, Eastern Region, Southern Region and Western Region. The interconnected transmission system within each region is also called the regional grid.

The transmission system planning in the country in the past had traditionally been linked to generation projects as part of the evacuation system. Ability of the power system to safely withstand a contingency without generation rescheduling or load-shedding was the main criteria for planning the transmission system. However, due to various reasons such as spatial development of load in the network, non-commissioning of load center and generating units originally planned and deficit in reactive compensation, certain pockets in the power system could not safely operate even under normal conditions. This had necessitated backing down of generation and operating at a lower load generation balance in the past. Transmission planning has therefore moved away from the earlier generation evacuation system planning to integrated system planning.

While the predominant technology for electricity transmission and distribution has been Alternating Current (AC) technology, High Voltage Direct Current (HVDC) technology has also been used for interconnection of all regional grids across the country and for bulk transmission of power over long distances.

Certain provisions in the Electricity Act 2003 such as open access to the transmission and distribution network, recognition of power trading as a distinct activity, the liberal definition of a captive generating plant and provision for supply in rural areas are expected to introduce and encourage competition in the electricity sector. It is expected that all the above measures on the generation, transmission and distribution front would result in formation of a robust electricity grid in the country.

1.1.4 Distribution

The total installed generating capacity in the country is **1,62,366 MW** as of June 2010 and the total number of consumers is over 144 million. Apart from an extensive transmission system network, at 500 kV HVDC, 400kV, 220kV, 132kV, 110 kV and 66kV, which has developed to transmit the power from generating stations to the grid substations, a vast network of sub-transmission in distribution system has also come up for utilisation of the power by the ultimate consumers.

However, due to lack of adequate investment on transmission and distribution (T&D) networks, the T&D losses have been consistently on the higher side, and reached to the level of 32.86% in the year 2000-01. The reduction of these losses was essential to bring economic viability to the State Utilities.

As the T&D loss was not able to capture all the losses in the net work, concept of Aggregate Technical and Commercial (AT&C) loss was introduced. AT&C loss captures technical as well as commercial losses in the network and is a true indicator of total losses in the system.

High technical losses in the system are primarily due to inadequate investments over the years for system improvement works, which has resulted in unplanned extensions of the distribution lines, overloading of the system elements like transformers and conductors, and lack of adequate reactive power support.

The commercial losses are mainly due to low metering efficiency, theft & pilferages. This may be eliminated by improving metering efficiency, proper energy accounting & auditing and improved billing & collection efficiency. Fixing of accountability of the personnel / feeder managers may help considerably in reduction of AT&C loss.With the initiative of the Government of India and of the States, the Accelerated Power Development & Reform Programme (APDRP) was launched in 2001, for the strengthening of Sub-transmission and Distribution network and reduction in AT&C losses. The main objective of the programme was to bring Aggregate Technical & Commercial (AT&C) losses below 15% in five years in urban and in high-density areas. The programme, along with other initiatives of the Government of India and of the States, has led to reduction in the overall AT&C loss from 38.86% in 2001-02 to 34.54% in 2005-06. The commercial loss of the State Power Utilities reduced significantly during this period from Rs. 29331 Crores Rs. 19546 Crore. The loss as percentage of turnover was reduced from 33% in 2000-01 to 16.60% in 2005-06.

The APDRP programme is being restructured by the Government of India, so that the desired level of 15% AT&C loss could be achieved by the end of 11th plan.

1.2 Power for ALL by 2012

The Government of India has an ambitious mission of ‘POWER FOR ALL BY 2012’. This mission would require that the installed generation capacity should be at least 200,000 MW by 2012 from the present level of 162,366 MW. Power requirement in India is expected to double by 2020 to 400,000 MW. The country's National Electricity Policy wants the entire billion plus population to have access to power by 2012 and to raise the per capita availability of electricity by nearly 50 percent. This goal requires another 40000 MW of capacity by 2012. The Indian economy is growing at one of the fastest rates in the world. This leads to a high demand for additional energy, in particular electricity, at the rate of 9 percent every year. India's electricity consumption is sixth globally and third in Asia with 612 units of per capita consumption per annum. It is set to increase to 1,000 units per annum by 2012. The power generation capacity has to grow by at least 10 percent to sustain the current GDP growth of 9 percent, say industry experts. Ideally, they say, the ratio of energy generation and GDP growth should be 1:1.

The government has set an ambitious capacity addition target of 78,557 MW during the country's 11th five-year economic plan period (2007-12). The envisaged capacity addition of over 76,000 MW comprises 58,644 MW or 75 percent in thermal, 16,553 MW or 21 percent in hydropower and 3,380 MW or 4 percent in nuclear power. Currently, 44,000 MW is under construction.

However, most experts dismiss this target as unrealistic given the country's past track record. During the 10th plan period (2002-07), which ended in March, the country could add just half of the targeted 41,000 MW. The story was not different during the ninth plan period (1997-2002), when only 19,000 MW or less than half the target was achieved.

On the distribution front too, there has been little solace in the overall transmission and distribution losses or the broader measure of aggregate technical and commercial losses. Over a third of the power generated fails to reach the consumer. The transmission segment also requires massive investment to boost capacity. The power sector will need investment of around $100 billion if it goes in for a capacity addition of 78,000 MW during the 11th Plan period. Of the total amount, $50 billion would alone be needed for raising the generation capacity while the rest would be required for transmission, distribution and related activities, says India's top bureaucrat in the power sector, R.V.Shahi. As such, the government's slogan of 'Power for all by 2012' sounds increasingly problematic.

However, one bright spot in this dismal scenario is that nuclear power and wind energy is looking up. India's emerging nuclear power sector received a major boost in mid-2006 when it signed a civilian nuclear cooperation agreement with the United States. The government recently announced plans for massive investments in nuclear power plants by 2030. Country is planning to reach its nuclear generation capacity 20,000 MW and scale it up to 40,000 MW by 2030 according to the Chairman, Atomic Energy Commission.

As for wind energy, India has emerged as the world's fifth-largest wind energy producer. Today, windmills dot the landscape in several southern and western states such as Tamil Nadu, Rajasthan, Gujarat and Maharashtra, producing a total of 6,000 MW of power. So far, wind energy accounts for a meager one percent of the total power produced in the country. Over the next five years, wind energy generation is expected to be more than double, with the addition of 8,000 MW to the existing capacity. That is still far short of India's potential wind-power generation, which has been estimated at 45,000 MW.

1.2.1 Objectives "Power for ALL by 2012"

- Sufficient power to achieve GDP growth rate of 8%
- Reliable power
- Quality power
- Optimum power cost
- Commercial viability of power industry
- Power for all

1.2.2 Strategies

- **Power Generation Strategy** with focus on low cost generation, optimization of capacity utilization, controlling the input cost, optimisation of fuel mix, Technology upgradation and utilization of Non-conventional energy sources

- **Transmission Strategy** with focus on development of National Grid including Interstate connections, Technology upgradation & optimization of transmission cost.

- **Distribution strategy** to achieve Distribution Reforms with focus on System upgradation, loss reduction, theft control, consumer service orientation, quality power supply, commercialization, decentralized distributed generation and supply for rural areas.

- **Regulation Strategy** aimed at protecting consumer interests and making the sector commercially viable.

- **Financing Strategy** to generate resources for required growth of the power sector.

- **Conservation Strategy** to optimise the utilization of electricity with focus on Demand Side management, Load management and Technology upgradation to provide energy efficient equipment / gadgets.

- **Communication Strategy** for political consensus with media support to enhance the general public awareness.,

1.3 Industrial Power Consumption in Kerala

Electricity at cheaper rate was the sole reason for attracting manufacturing industries to the state of Kerala till 1980s. After the commissioning of 780 MW capacity Idukki Hydroelectric Project in 1976, not a single project of similar capacity was executed in Kerala's Hydel Power Sector. The state started witnessing acute power shortages right from 1983 onwards mainly because of the demand – supply mismatch. In other words, the additional power generation actually taken place was much less compared to the ever-increasing demand of electricity. The reasons for steady increase in demand are mainly attributed to the following:

(a) Lower price of electricity mainly in the agriculture and the residential sectors as compared to the real cost of supply of electricity

(b) Increased personal income and penetration of consumer durables,

(c) Rapid pace of urbanization

(d) Level of activity in individual electricity using sectors,

(e) Increasing penetration of irrigation pump-sets due to mechanization of agriculture

(f) Changes in the composition of GDP, and

(g) Changes in technology.

The industrial electricity consumption in Kerala was about 60 % of the total consumption during early 1980s. At present the industrial electricity consumption by the High Tension (HT) & Extra High Tension (EHT) consumers account for 28 % of the total energy sales to the consumers by KSEB and they contribute about 37 % of the total revenue collected from tariffs. The contributing factors for a comparative low level of industrial consumption are the permanent closure of power intensive manufacturing industries on account of unaffordable tariff and increase in domestic and commercial consumption due to increase in pace of urbanisation and high level of consumerism in the state and other factors mentioned above. The tariff as applicable to the HT & EHT Industrial Electricity consumers is comparatively higher than domestic or agricultural tariff even though the actual cost of supply or the 'cost to serve' of industrial power per unit is much lesser than that of domestic, agricultural and other low tension (LT) supply.

Some characteristics of the Industrial consumers that benefit the Board are:

(a) They are the subsidising category of consumers for the Board. Hence they are the revenue earners ensuring better returns for the Board.

(b) The Load curve and consumption pattern enable better capacity utilisation and low Cost of Service for the Board in comparison to LT consumer categories.

1.4 Kerala's Power Sector & KSEB

1.4.1 Introduction

The Kerala State Electricity Board is the single statutory body in the state responsible for generation, transmission and distribution of electricity in the state of Kerala. The Kerala power system consists of 13 Hydel stations, 11 small Hydel stations, 2 captive power plants, 2 thermal stations, 3 IPPs, and 1 windmill. The grid is connected to the Southern Region Transmission system through two 400 kV double circuit lines at Madakkathara and Thiruvananthapuram. There are 5 major inter-state transmission lines. The major substations include one 400 KV sub-station, and fourteen 220 KV substations and four 220kV substations are under construction. The main grid comprises of the 220 KV systems.

The projected energy sale for the year 2010-11 is estimated as 14830.10MU. The actual T&D loss within KSEB for the year 2008-09 was 18.83%. The projected total energy requirement within the state for the year 2010-11 is 17821.18 MU considering the regional losses, total energy requirement would be 18203.16 MU. KSEB expect an overall increase of 1029.03MU (6%) during the year 2010-11 over 2009-10.The highest peak demand in the system met during the last year was 2911 MW on 2 November-2009, it was about 22% higher than the peak demand met during previous year and on average basis annual growth is 6% over 2007-08. KSEB expect the annual growth of 6% in peak demand during the year 2009-10 and 2010-11 over the peak demand met during 2007-08 (the year without demand restriction / power cut). The peak demand projection for the year 2010-11 is 3280 MW.

The Kerala State Electricity Board (KSEB) is a statutory body constituted on 01-04-1957 under Section 5 of the Electricity Supply (Act), 1948 for the coordinated development of Generation, Transmission and Distribution of electricity in the State of Kerala. As per the provisions of the Electricity Act-2003, KSEB continued as a State Transmission Utility (STU) and Distribution Licensee till 24-09-2008, performing same functions of generation, transmission and distribution of electricity within the State of Kerala. In exercise of powers conferred under sub-sections (1), (2), (5), (6) and (7) of section 131 of the Electricity Act, 2003, State Government vide the notification G.O (Ms). 37/2008/PD dated 25th September, 2008 has vested all functions, properties, interests, rights, obligations and liabilities of KSEB with the State Government till it is re-vested the same in a corporate entity. Accordingly, KSEB has been continuing all the functions as a Generator, State Transmission Utility and a Distribution Licensee in the State.

In tune with the increase in electricity demand of the State, KSEB has been performing the planning and development of the power system over the years by utilizing the resources in the State. As on March 2010, KSEB is catering the electricity needs of about 99 lakhs consumers in the State.

As a Government owned public entity, KSEB has been implementing all the policy directions of the State Government such as providing free electricity to consumers below poverty line, giving priorities for service connections to weaker sections in the society, subsidy to Agricultural consumers, Orphanages and other eligible consumers as decided by the Government from time to time, tariff concessions to Industrial sectors etc. KSEB has been implementing various schemes formulated by Central Government such as APDRP, RGGVY schemes in the State towards accomplishing the national goals such as cent percent household electrification, electrification of all dwellings, settlements etc.

The growth of the Kerala power system during the last 50 years is given in the Table No.1.1 below.

Table No.1.2

Growth of Kerala Power System

Year	Inst. Cap. MW with in the State				Annual Sales MU	No of Consumers (Lakhs)	Per Capita Conspn. kWh	EHT lines Ckt Kms	EHT S/s (Nos)	HT lines Ckt Kms	LT lines Ckt Kms	Dist Trfrs (Nos)
	Hydel	Thermal (Incl. IPPs)	Wind	Total								
57-58	109.0	0	0	109.0	363	1.06	19	1600	15	3851	4980	1862
60-61	133.0	0	0	133.0	518	1.75	30	1900	22	5449	8899	2898
73-74	622.0	0	0	622.0	2121	7.77	79	3378	59	9645	25968	8285
80-81	1012.0	0	0	1012.0	4499	15.72	109	4638	92	14189	55963	11656
85-86	1272.0	0	0	1272.0	4172	23.96	136	5317	109	16917	76141	13314
90-91	1477.0	0	0	1477.0	5331	34.50	185	5885	140	20221	101834	17838
97-98	1676.5	85.3	2	1763.8	7716	52.11	239	7074	168	27083	138732	26826
98-99	1692.5	336.2	2	2030.7	9182	56.39	285	7381	177	28090	174196	28058
99-00	1742.5	594.2	2	2338.7	9812	60.30	300	7599	179	28672	180499	29551
00-01	1792.5	614.6	2	2409.1	10319	64.46	311	9085	194	30035	187169	31329
01-02	1795.0	771.6	2	2568.6	8667	66.62	395	9274	204	30971	191931	32585
03-04	1807.0	591.6	2	2400.6	8910	73.00	391	9718	225	33323	201638	34758
04-05	1843.6	591.6	2	2437.2	9384	77.99	400	9924	251	33998	207711	36442
05-06	1849.6	591.6	2	2443.2	10906	82.98	427	10178	269	35060	215152	38193
06-07	1849.6	591.6	2	2443.2	11331	87.14	465	10593	276	37891	223370	39872
07-08	1851.6	591.6	2	2445.2	12050	90.3	470	10650	281	38227	234252	42401
08-09	1886.5	591.6	23.9	2502.0	12414	93.6	470	10855	299	41245	241888	46510

Source: Kerala State Electricity Board, Vydhyuthi Bhavanam, Trivandrum

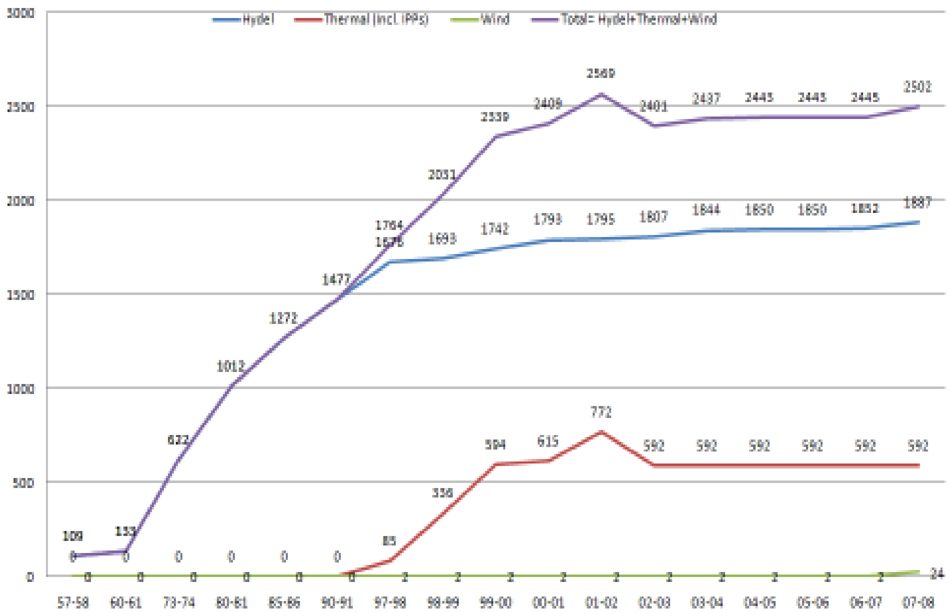
The consumer strength has increased from 1.06 lakhs in 1957 to 93.6 lakhs in March 2009. The installed capacity with in the State has increased from 109 MW in 1957 to 2502 MW in 2008-09. In addition to this, KSEB has an allocation of about 1041 MW from Central Generating Stations of NTPC, NLC and NPC.

1.4.2 Features of Kerala Power System

The Kerala Power system has certain unique characteristics, which are adverse to the efficient functioning of the system. Kerala is relatively poor in energy resources. There are no known reserves of coal, oil or similar fossil fuels in Kerala. The main source of energy in Kerala is its hydro electric potential. By harnessing just 1886.5 MW of the vast hydro potential of the State so far, the Board has been able to provide electricity at relatively lower rates to the consumers for the last few decades. Table No. 1.1 and figures 1.4 & 1.5 shows the growth of Kerala Power System viz. installed capacity, annual sales, number of consumers, per capita consumption, circuit kilometers etc.

Figure No.1.4

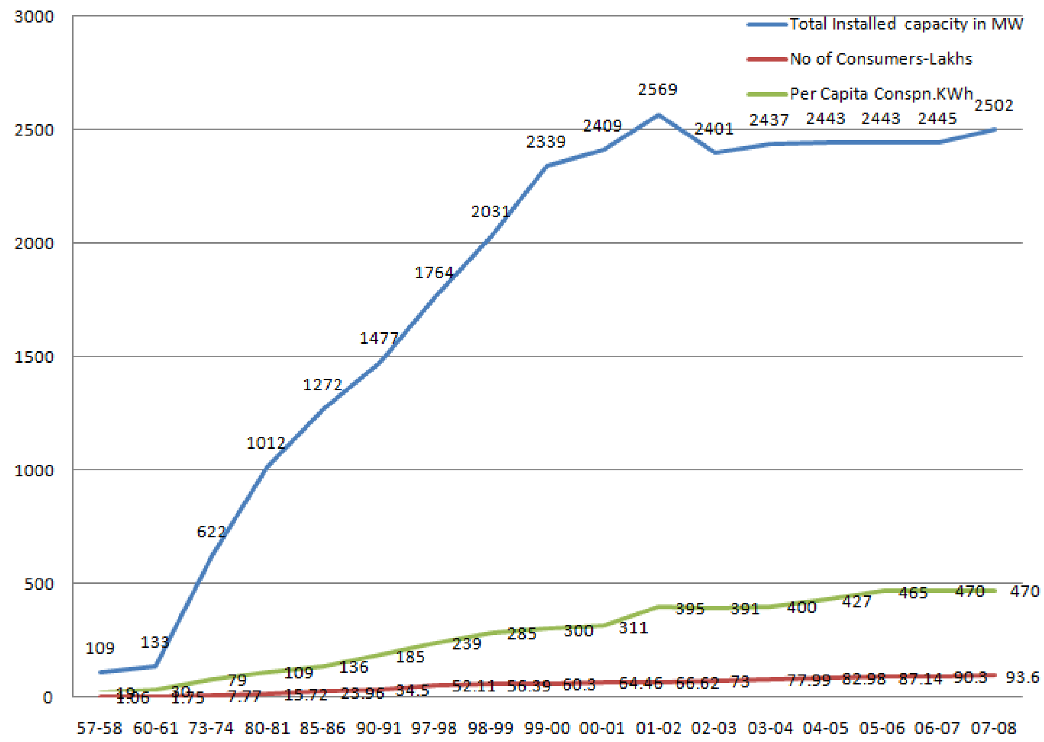
Growth of installed capacity of power in Kerala



Source: Kerala State Electricity Board, Vydhyuthi Bhavanam, Trivandrum

Figure No.1.5

Growth of capacity, consumers and per capita consumption



Source: Kerala State Electricity Board, Vydhyuthi Bhavanam, Trivandrum

Some of the characteristics of the Kerala Power System are discussed below:

1.4.2.1 Dependency on Monsoon:

The generation from Hydel plants is largely dependant on the Southwest and Northeast monsoons received during the months from June to November of a year. The State receives 65% of the annual rainfall from the South-West monsoon, and 20% from the North-East monsoon. The monsoon received widely fluctuates from year over year and at times, there are drastic variations severely affecting the generation of hydropower. Only tapping more and more hydel potential can minimize the adverse impact of vagaries of monsoon. But due to environmental and other public issues, Board could not add more Hydel capacity in tune with the increase in demand.

1.4.2.2 Hydro - thermal ratio

As explained earlier, KSEB could not start more Hydel projects in tune with the increase in electricity demand. So, the State became more and more dependant on the high cost thermal power, especially from liquid fuel stations set up within the State. This has resulted change of the hydro-thermal mix from 85:15 in 1992-93 to 40: 60 in 2008-09 and consequent heavy expenditure on power purchase.

1.4.2.3 Adverse Consumer-mix

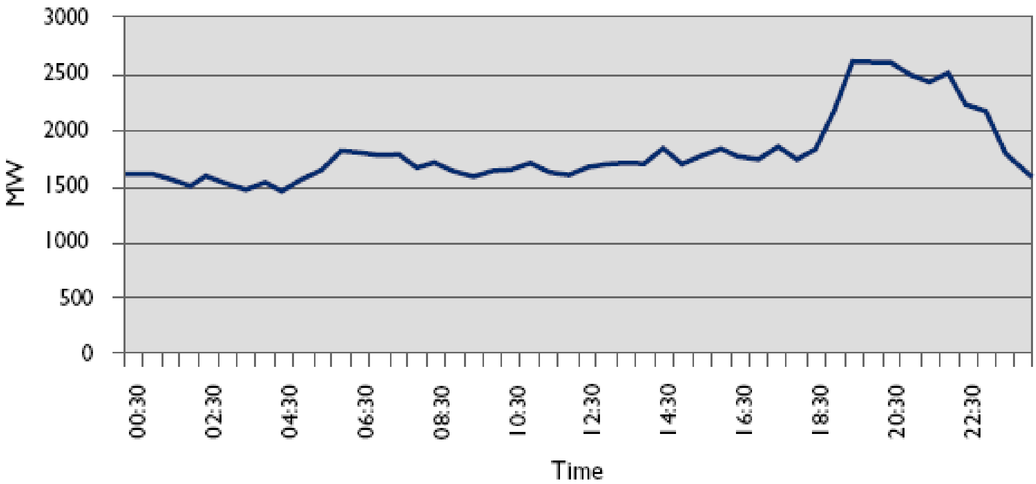
The composition of the consumers and the pattern of their consumption has also undergone major changes. Though availability of cheap electricity in the past had attracted energy intensive heavy industries to the State, the industrial development of the State has been affected due to various other factors. The industrial consumption in the State has not increased appreciably during the last few years. At the same time, there has been steady growth in the number of domestic and commercial consumers. During the last few years, an average 5.0 lakhs LT consumers were annually added to the system and out of this about 78 % were domestic consumers. The electricity is supplied to the domestic consumers at considerably subsidized rate. The average revenue realized from them is about Rs. 1.90 per unit. The steep rise in domestic consumption coupled with the stagnant industrial consumption has seriously affected the revenue of the Board. However, the commercial and industrial consumers compensated low revenue from the subsidized domestic sector by way of cross-subsidy. This imbalance has been widening due to the increase in domestic consumption.

1.4.2.4 High Peak Load

In addition to the low revenue return, the domestic consumers contribute steep rise in consumption during peak hours (peak load hours – 6 pm to 10 pm). Now the peak load demand in the State is almost twice the demand during off-peak hours. To meet the increase in demand during the peak, heavy investment has been made to enhance the system capacity/ or procuring energy at high cost. Due to the wide variation in peak and off-peak demand (Refer Fig.1.6, Kerala Load Curve) the capacity created to meet the peak demand is being kept idle for most part of the day.

Figure 1.6

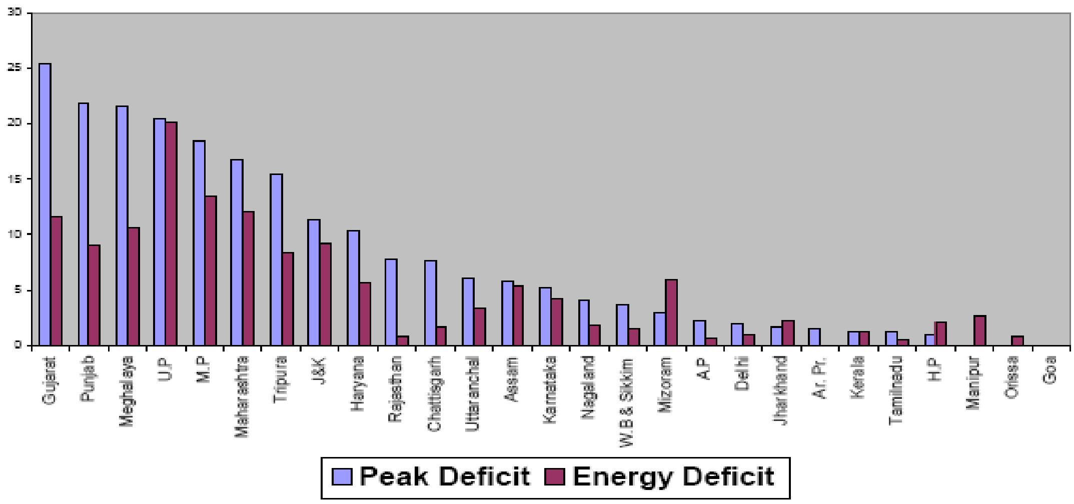
Load Curve - Kerala Power System



Source: Report on Establishment of Kerala State Energy Conservation fund by International Resources Group, Ltd. (For EMC, Kerala)

Figure No. 1.7

Peak Power and Energy Shortages in States/UTs. In 2004-05



Source: Planning Commission of India- Draft report on integrated energy policy 2005

From the figure no.1.7 it can be seen that Kerala's power requirement is more or less matching with power availability during peak hours. During peak hours KSEB is maximising own generation and availing the allocated share from the Central Generating Stations. However, during off-peak hours Kerala demand is only about half of that of peak demand (figure-1.6).

1.4.2.5 High Cost of thermal power.

To meet the increase in electricity demand, KSEB has commissioned two thermal plants – one in Brahmapuram (Kochi) (106.5 MW) and the other in Kozhikkode (128 MW). These plants are driven with Low Sulphur Heavy Stock (LSHS) fuel for generating electricity as the primary fuel and start up fuel is HSD. There is also one private owned LSHS based thermal station (IPP) of 20 MW at Kasaragode (KPCL). In addition to the above, there are two Naphtha based thermal plants in Kerala viz., the NTPC's RGCCPP Kayamkulam (360 MW) and BSES plant at Kochi (163 MW). Due to global factors, price of LSHS and Naphtha are heavily fluctuating. During July-2008, the per unit cost of electricity from Naphtha based plants was about Rs 12.00 per unit and at the same from LSHS was Rs 10.00 per unit. Recently, the price of Naphtha was come down and as result the cost of generation has also come down drastically. Because of the volatility in petroleum prices, there is wide variation in the cost of generation of power from the thermal power plants within the state.

1.4.2.6 Adverse LT-HT ratio

Kerala is one of the most densely populated states in the country. As per the census conducted in 2001, the total population in Kerala is 31.83 million. About 23.57 million (74%) of the population live in villages, rural areas and remote places in high ranges. The rural population in Kerala, unlike in other states in India, do not live in clusters of houses forming Basthis, Hamlets or large villages and they live in individual houses built within their agricultural land segregated in distance from their neighbours. Because of this peculiarity of living pattern, more low-tension (LT) lines have to be built to supply electricity to rural houses. The ratio of Low Tension distribution lines to the High Tension lines is 6:1 in Kerala against the norm of 1:1. This high LT/HT ratio has adverse effect on the investment cost of distribution network as well as the distribution losses. KSEB is targeting to reduce the LT-HT ratio to 4:1 by the end of the 11th plan.

The mission of KSEB is to supply quality power at affordable cost on demand to the people of the State, endeavor to supply quality and uninterrupted power, improve the consumer satisfaction and to act as a catalyst for development of the State. The Board, though a State undertaking, required to function on commercial principles, cannot evade the social obligations to general public, in the midst of economic reform process underway in the country.

The State Load Dispatch Station situated at Kalamassery manages the grid. There are three Sub Load Dispatch Centres – at Thiruvananthapuram, Kalamassery and Kannur (Kanhirode). The Load Dispatch activities are carried out with the aid of state-of-the-art technology Computerized Supervisory Control and Data Acquisition System (SCADA). Real-time data from 30 Remote Terminal Units including generating stations and major sub-stations are acquired at the Load Dispatch Station. One more RTU is being installed. The data acquisition is through the communication network installed and maintained by the Board comprising of microwave link from Thiruvananthapuram to Kalamassery and Fibre Optic (FO) link from Kalamassery to Kannur. Data from remote stations are collected through Power Line Carrier Communication Network (PLCC) to the nearest nodal station in the broadband network. The state LD Station is connected to the Southern Regional Load Dispatch Centre, Bangalore, through FO link for real time data transfer. The real time generation details of all central sector stations are made available through the SRLDC.

The State Load Dispatch Centre schedules generation from various generating stations, central sector stations and IPPs depending on the load condition and the real time frequency. Transaction of unscheduled energy from the pool when the frequency profile is favourable is coordinated by the SLDC effectively. The Load Dispatch Centre also monitors the transmission system and issues sanction for shutdowns. Water availability, inflow, consumption, demand etc. are daily collected and monitored in the Load Dispatch Station.

The major activities undertaken by this wing are:

1. Daily Scheduling of Generation
2. Short term and long term planning of Generation Schedule
3. Preparation of Load Generation Balance Reports on short term and long term basis
4. Verification of energy drawls from various Central Generating Stations (CGS) and Regional Energy Accounts
5. Verification of energy availed on unscheduled basis from the central grid depending on the frequency.
6. Certification of energy generated from all internal generating stations and the energy received on the grid.
7. Maintenance scheduling of generating units and transmission lines.
8. Economic load dispatching
9. Grid discipline
10. Load forecasting and demand estimation
11. System security and islanding facility
12. Black start preparedness
13. Event analysis and preventive measures
14. Coordination with neighbour Grids
15. Public relation and consumer interaction.
16. Certification of availability of generating stations and transmission system.

17. Maintenance of the communication network, communication equipment and SCADA system
18. Protection coordination, commissioning and troubleshooting of protection schemes at all substations and generating stations.
19. Performance monitoring of major grid elements like power transformers, instrument transformers, generators, capacitor banks, etc.
20. Undertakes testing and commissioning of protection schemes of major EHT consumers on a payment basis.

1.5 Significance of the study:

Industrial Electricity consumption in the State was about 60 % of the total consumption till early 1980s. Kerala State was one of the most favored destinations for setting up manufacturing Industries. Major industrial units like FACT, INDAL, TCC were established during 1940s by the initiative of the then Maharajah of erstwhile Travancore State. Kerala's first and foremost hydroelectric power project called Pallivasal was commissioned in the year 1939 with an intention to provide electricity at cheaper rates to facilitate industrial development and economic growth of the Travancore State. The performance of SEB in the State was quite well until 1980s. From then on there has been deterioration in the performance, which can be traced to failures on four fronts:

a) **Techno-economic** - High losses, low efficiency, poor project implementation etc.

b) **Policy** - Poor targeting of subsidy, shifts in fuel choice and approach to self reliance etc

c) **Planning -** Overemphasis on centralized supply approach, neglect of end use efficiency etc and

d) **Governance -** Undue interferences in SEB functioning by the State Government, corruption, undue delays in executing projects, bad management etc.

The distortions caused by these failures led the sector into a crisis in the beginning of the 1990s. The crisis in the electricity sector has three important components:

a) **Performance crisis** – Low efficiencies and lethargic administration

b) **Financial crisis** – Stagnant revenues, increasing expenditure, increasing arrears, increasing losses, lack of capital and

c) **Credibility crisis** – Loss of credibility in the eyes of consumers, common citizens and funding agencies.

Before the establishment of State Regulatory Commission, State Electricity Board was authorised to set consumer tariffs so as to achieve a surplus of 3 % on the value of fixed assets. In practice, the State Government approved the tariffs without seriously questioning the SEB's efficiency or costs. The industrial consumption in the State has reduced from 60 % in 1980s to 30 % in 2008-09 and a number of power intensive industrial units have been wound up due to spiraling increase in electricity charges. With the establishment of State Regulatory Commission, the situation has changed.

A study on variation in industrial tariff before and after the setting up State Regulatory Commission and the impact of ERC in the performance of KSEB to be conducted in detail.

1.6 Statement of the problem:

Electricity is the prime mover of economic activities in any State. Survival of industrial consumers especially power intensive consumers in the State depends up on affordable or economically viable tariff rates offered by the Utility (SEB). Electricity Tariff of High Tension (HT) and Extra High Tension (EHT) industrial electricity consumers had undergone several revisions in the pre-regulatory period especially during 1997 to 2002. The industrial power consumption in the state has come down from 60 % of the total power consumption in early 1980s to 28 % of the total power consumption in 2009-10.

The period from 1997 to 2010 can be broadly divided into two separate periods viz. pre-regulatory regime and regulatory regime. Before the establishment of Kerala State Electricity Regulatory Commission (KSERC), KSEB was authorised to set consumer tariff so as to achieve a surplus of 3 % on the value of fixed assets. In practice, the tariff hike was affected by KSEB with the approval of State Government. The State Government's decisions to increase tariff, mainly industrial tariff was adhoc and arbitrary and without seriously questioning the efficiency parameters, costs and financial performance of State Electricity Board. This has resulted in heavy cross subsidization by industrial consumers mainly High Tension and Extra High Tension Consumers (HT & EHT) to other categories of consumers. When the overall industrial consumption has come down progressively from 60 % to 28 %, the industrial consumers were forced to take more burden of cross-subsidy on its shoulders.

State Electricity Boards (SEBs) like KSEB have been functioning as vertically integrated monopolies with the State Governments regulating its function. Vertical integration implies the same utility handles the functions of generation, transmission and distribution of power. Monopoly implies the absence of any competition. With the establishment of State Regulatory Commission, the situation has changed and the whole process of tariff revision has taken a different route.

After nearly three years of drafting, the Electricity Act 2003 was enacted by the Parliament, the apex legislative body in the Republic of India, representing the will of the entire people of India in June 2003 with the following intent:

"An Act to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity and generally for taking measures conducive to development of electricity industry, promoting competition therein, protecting interest of consumers and supply of electricity to all areas, rationalisation of electricity tariff, ensuring transparent policies regarding subsidies, promotion of efficient and environmentally benign policies, constitution of Central Electricity Authority, Regulatory Commissions and establishment of Appellate Tribunal for Electricity and for matters connected therewith or incidental thereto."

The electricity Act - 2003 marks a watershed in the Indian Power Sector, with fundamental and far-reaching impacts on reform, deregulation and restructuring. The State Electricity Regulatory Commission is expected to work as a watchdog to ensure a vibrant power sector in the State by ensuring the overall growth and development of power sector in the State viz. Improvement of operating efficiencies, rationalization of tariff, cross subsidy minimization, eliminating non-value adding activities, minimizing Transmission and Distribution losses, minimizing Commercial and Technical (C&T) losses, timely implementation of capital expenditure plans, encourage competition, enhance speed and accountability and to fulfill all other regulatory objectives as envisaged in the Electricity Act 2003.

In broader terms, the main objectives of KSERC are reform, deregulation and restructuring of State Power Sector to make it more and more vibrant.

1.7 Objectives of Study:

The following are the major objectives of study:

1. To understand the Industrial Electricity Tariff prevailed in Kerala State during the period 1997 to 2010 by taking the EHT tariff as the representative data and find out the variation in Tariff structure during the above period.
2. To understand the impact of tariff variation of one of the major EHT Industrial Electricity Consumers in the state and its consequential impacts like loss of production, loss of revenue, loss of employment etc.

3. To understand the impact of intervention of regulatory regime in the State of Kerala in the areas of industrial tariff, operating performance of KSEB including T&D loss reduction, scheduling and generation of power, power purchase etc.

4. To understand the compliance of KSEB and Kerala State Electricity Regulatory Commission in meeting the key provisions of Electricity Act 2003, National Power Policy and National Tariff Policy in general and other regulations pertaining to tariff fixation and finalisation of ARR & ERC (Annual Revenue Requirements and Expected Revenue from Charges).

1.8 Hypothesis:

On the basis of the objectives stated above, it is hypothesized that:

a) There was no increase in tariff for High Tension and Extra High Tension Industrial Electricity Consumers since the inception of Kerala State Electricity Regulatory Commission

b) There are significant improvements in the following areas of Power Sector in Kerala:

   - ❖ T&D loss reduction,
   - ❖ Optimum scheduling, internal generation and power purchase,
   - ❖ Reduction in Interest burden of KSEB
   - ❖ Transparent process of decision-making
   - ❖ Consumer Grievance Redressal

c) There are willful deviations in many areas from the provisions of Electricity Act 2003, National Energy Policy 2005 and National Tariff Policy 2006 by the KSEB.

1.9 Methodology:

The study is mainly based on secondary data collected from Kerala State Electricity Regulatory Commission, Kerala State Electricity Board and the Kerala High Tension and Extra High Tension Industrial Electricity Consumers Association.

Published information on scheduling and generation of power, purchase of power, T&D loss data, C&T loss data, capital expenditure, repayment of loans etc will be analysed to determine performance and efficiency improvement. Simple statistical tools like average, percentage variation etc will be used for analysis.

Compliance to the relevant provisions of Electricity Act-2003, NEP-2005, NTP-2006 by KSEB and KSERC will be scrutinized with the help of published ARR&ERC orders of the KSERC, ARR & ERC Petitions filed by the KSEB and the objections raised by consumers in general and industrial consumers in particular.

1.10 Limitations:

The study is primarily based on secondary data available with Regulatory Commission, KSEB and Industrial Electricity Consumers, which are authentic and accurate. Since KSEB has not completed the unbundling process, segregation of assets and liabilities of generation, transmission and distribution wings are still remain incomplete.

1.11 Scheme of the study:

The study has been arranged into eight chapters as given below:

Chapter – I deals with Introduction, review of Power Sector, significance of the study, statement of the problem, objectives of the study, methodology, limitations of the study and scheme of the study.

Chapter – II deals with literature review

Chapter – III deals with World Energy Demand and Economic Outlook

Chapter – IV deals with economic aspects of power sector, different types of electricity tariff, different pricing methods of electricity

Chapter – V deals with Process and principles of regulatory review, cost plus method, performance based regulation, principles of tariff setting, process of tariff approval, tariff philosophy etc.

Chapter – VI deals with tariff regulatory framework in Kerala, relevant provisions in Electricity Act -2003, National Electricity Ploicy-2005, National Tariff Policy-2006 etc.

Chapter – VII a case of power tariff hike with respect to a power intensive consumer in Kerala.

Chapter – VIII deals with analysis on impact of regulatory regime in Kerala

Chapter – IX deals with major findings, suggestions and conclusions of study

CHAPTER-2

LITERATURE REVIEW

2.1 Introduction

The objectives and hypothesis of the study explained in the previous chapter are formulated in accordance with a detailed and thorough review of relevant literatures comprising of books, journals, periodicals and published documents pertaining to functioning, performance and regulation of power sector in India. While a few of them are focusing on theoretical framework a good many are related to the practical applications of the concepts.

2.2 Definitions of Regulation

The term 'regulation' refers to the various instruments by which the governments impose requirements on enterprise and citizens. It thus embraces laws, formal and informal orders, administrative guidance, and subordinate rules issued by all levels of government or professional self regulatory bodies to which governments have delegated regulatory powers.

The judgment of *Air India Statutory Corporation vs United Labour Union*[1] held, 'The legislature passes laws within the overall constitutional framework. These laws are state policy. Its implementation is by the executive. The person(s) implementing the laws are regulators who are regulating the implementation. A regulator must convert the legislation into rules, regulations and procedures that make it possible to achieve the intentions of the legislation. Legislation can lay down general directions or it can be very detailed. I whichever manner the legislation may be drafted, the implementing bureaucrat exercises varying degree of discretionary authority as he interprets the law.'

---

1 Supreme Court proceedings, MANU/SC/0163/1997

This discretional authority is not different from the policy–making authority of the legislature. Of course, the legislature could - if he wishes – legislate in greater deal as in countries like Chile. However, in any event, the regulator is constrained by the boundaries of the legislation that he has to implement. When the legislation is not precise or is ambiguous, there is scope for the regulator to interpret it and even to stretch his authority under the shelter of that interpretation. To the extent that the legislation has drafted the legislation loosely, many major and minor policy decisions might be taken during the implementation. If the legislation is drafted in a very tight fashion, the flexibility required because of the varying local situations might make the implementation process excessively constrained. The drafting of legislation has to strike a balance between flexibility for the implementing agency and ensuring that the intention of the legislature is carried out. The American and Indian legislative processes produce legislation that provides flexibility; the Latin American legislation is much more close drafted and lays down considerable detail, thus reducing the extent of flexibility.

As an example, the Indian law (Electricity Regulatory Commissions Act 1998; now repealed by Electricity Act 2003) asks regulators to promote efficiency, and economy; encourage investment in the sector; and safeguard consumer interest[2]. It does not lay down the targets for transmission and distribution losses, metering, extent of rural electrification, electricity quality, return on investment to investors in generation, etc. As a consequence, these have been left to the ERCs (Electricity Regulatory Commissions) to decide. However the Central Electricity Regulatory Commission and State Regulatory Commissions have issued, consequent to the enactment of Electricity Act-2003, necessary policy directives.

In *Black's Law Dictionary*, 'regulation' is defined as 'the act of regulating, a rule or order prescribed for management or Government; a regulating principle; a precept, rule, or order prescribed by superior or competent authority relating to action of those under its control'.

[2] Section 13(d) of the Electricity Regulatory Commissions Act, 1998

In *Corpus Juris Secundum*, it has been provided that the power to regulate carries with it full power over the thing subject to regulation and, in the absence of restrictive words, the power must be regarded as plenary or in the interest of the public. It has been held to contemplate or employ the continued existence of the subject matter.

In *Craise on Statute Law*, it is stated that if the legislation enables something to be done, it gives power at the same time 'by necessary implication, to do everything, which is indispensable for the purpose of carrying out the purposes in view'. Thus the legislation sets out objects it seek to achieve and lays down the responsibilities, authorities and penalties and the regulator has to formulate the rules, principles etc in order to carry them out. For example, the National Tariff Policy – 2006, which is modeled on Chilean regulatory law and lays down extremely detailed rules for tariff determination.

2.3 Policy formulation, policy implementation, and regulation

While *Black's law Dictionary* refers to policy as 'the general principles by which a government is guided in its management of public affairs or the legislature in its measures', *Webster's Third International Dictionary* defines policy as 'a definite course or method of action selected (as by a government institution, group or individual) from among alternatives and in the light of given conditions to guide and usually determine the present and future decision.' While in general sense, policy could be understood as principles and guidelines around certain issues within the broad framework of which laws are made and translated into action, it specifically refers to a proposed course of action adopted by, for example, an individual, a group, an institution, or a government to realize a specific objective or purpose within a government environment. In other words, it is the policy that lays down the framework within which organizational goals are to be accomplished. The objectives of an organisation, which are often vague and general, are concretized in the policy goals, which set the administrative wheels in motion.

Policymaking is a very complex process and there exists some confusion regarding policy formulation, its conversion into acts through legislation, and the implementation of these acts. In fact, the confusion has stemmed mostly from the politics – administration dichotomy model in public administration propounded by Woodrow Wilson. This model refers to the sharp distinction drawn between politics and administration. While politics was concerned with laying down of policies, the administration's task was to carry out these policies as economically and efficiently as possible. Thus, the spheres of the two were made to appear quite separate and distinct. While Woodrow Wilson, the father of public administration, in his article titles *'The Study of Administration'* (Wilson 1966), considered politics and administration as separate processes and attempted to conceptually distinguish between the two areas of study, Goodnow (1990) observed that politics has to do with the policies or expressions of state while administration has to do with the execution of such policies. Thus policy making was regarded as the realm of politics, execution was considered as the realm of public administration. As opposed to this model the latest theories of policy-making emphasis the need of multiple agencies in policy making. In earlier literature, while the focus was on legislature and the role of executive in the formulation stage during which bills become acts, more recently a number additional stages have been identified in the policy making process. According to the 'policy cycle' theory they include agenda setting for policy initiation, formulation, implementation, evaluation and review.

While policy initiation sets the agenda by defining certain problems and issues as matters that engage the interests of the government, policy formulation is seen as a critical stage in policy process as it develops a political issue into a firm policy proposal through a process of debate, analysis and review. Policy implementation, on the other hand, comprises the actions through which policy is put to effect, sometimes in ways that differ from the original intentions of policy makers as Edelman (1964) observes, policies in American politics are largely symbolic. They are often vague and general and the actual meanings are attached during implementation.

It is clear that policy making is a complicated and interactive process and the content of policies is not merely determined ion the decision making phase. Rather as Nelson (1996) observes, policy content is negotiated over and over again in problem definition, legislation, regulation, and court decisions and yet again in the decisions made by street-level bureaucrats. While arguing in favour of insulating administration from partisan political interference, Goodnow (1990) stated that when one moves beyond general execution to specialised administration (as in the case of present-day regulators having specialised knowledge, technical expertise, and quasi judicial authority), 'much must be left to official discretion, since what is demanded of the officers is not doing of a concrete thing but the exercise of judgment'.

Thus it is clear that policy-making does not end with cabinet decision on a particular issues or the legislature's enactment of law. In fact, it takes place at various stages and at various levels. In implementing laws or acts (based on government policies) passed by the legislature, by drafting concrete rules and regulations for smooth transaction of government business, administrators (executives) at every level of bureaucracy interpret policy by applying their own judgement and regulate the behavior of members of the society. It thus appears that policy implementation necessarily involves some amount of 'discretion', which the administrators (as regulators) apply to define and refine it periodically.

'Delegated legislation' is the means by which the legislature delegates the executive withy law making power on a variety of complex issues. It empowers the administrator to design the detailed rules and regulations within their discretion. With the expansion in the functions of the government, laws have to be made on a variety of issues. Many of these are complex. Legislators may not have the expertise or time to understand them. This gives the opportunity for the executive to interpret and make rules that would otherwise have been in the legislation.

The growing complexity of public policy continues to erode the effectiveness of traditional command - and - control techniques of the government bureaucracy. Until fairly recently, most tasks undertaken by the national governments were simple enough to be organized along traditional bureaucratic lines. Once a policy or programme as enacted, the details of its operation could be formulated and appropriate commands issued by highly centralised centres. 'By contrast, the single most important characteristics of newer forms of economic and social regulation is that their success depends on affecting the attitudes, consumption habits, and production patterns of millions of individuals and hundred of thousands of firms and local units of government. The tasks are difficult not only because of they often deal with technologically complex matters but even more because they aim ultimately at modifying expectations' (Schultze 1977). In this context, credibility becomes an essential condition of policy effectiveness and achieving this requires delegating powers to designated institutions.

2.4 The nature of regulation

The nature of regulatory powers or functions that traditional administrators enjoy involves drafting of clear and concrete rules and regulations concerning the subject and implementing or enforcing them. It thus involves only legislative and administrative powers and does not confer judicial powers.

In contrary to old style regulation, independent regulatory commission – as they have come into existence since the mid 1990s – wield regulatory powers with legislative, executive, and judicial jurisdiction and are termed as quasi-judicial authorities. As Phillips (1993) observes, 'The independent regulator considers information available to him as well as evidence presented by the company and interveners, and makes a decision when prescribing certain rules of conduct for a utility, such as fixing prices. Contrary to the basis pattern of American government, which is based on the doctrine of separation of powers, a commission assumes the charge of administrator, judge, and legislator. When investigating rates or service and safety standards, a commission performs an administrative function. When holding hearings, examining evidence and making decisions, a commission acts as a judge of the utility's conduct. Moreover, the commission can even determine the rules it wants to administer, and it can decide to prosecute a utility and gather evidence against the firm. It then sits in judgement on the evidence collected by bit. This suggests that the independent regulatory commission acts in a legislative capacity as well'. A similar comment is made in the report of the Indian Parliamentary Standing Committee when examining the Electricity Bill (2001), which is now the Electricity Act (2003).

In addition to technical expertise and specialised knowledge, the quasi-judicial power to hear petitions, examine evidence, and take decisions differentiates today's independent regulatory authorities from the traditional public administrations entities.

2.5 Why Independent Regulators?

Independent regulation has been practiced in the US longer than anywhere else. An important justification used for the creation of IRAs (Independent Regulatory Agencies) is that they enable complex matters to be considered without discrimination between parties. A variety of disciplines have to interact for reaching a conclusion. The task is therefore delegated to a group of experts, who concentrate on such matters to the exclusion of others.

The need for expertise sometimes accompanies the requirement for rule-making, decision-making, and adjudicative function that may be inappropriate for a government department or a court (Galligan-1996). Sometimes a government department may be perceived as not being able to provide insulation from external influences. As far as the courts are concerned, it is considered difficult to develop in them the different kinds of expertise required. New specialised bodies with judicial powers are needed. A new administrative agency is therefore created to perform this function. Further, the expenditure of the time and prestige of the highly qualified senior judges on such specialised issues is not justified, given their other judicial workload.

The Parliamentary Committee that examined the Electricity Bill-2003, mentions that these ERCs (Electricity Regulatory Commissions) combine with themselves the powers of rule-making (legislative) and implementation and enforcement (executive) with the quasi-judicial powers of review and appeal against their orders (judicial). Joskow (1997) says, 'Contrary to the basic pattern of American government, which is based on the doctrine of separation of powers, a commission assumes the tasks of administrator, judge and legislator.' This fundamental change in the separation powers through this institution of independent regulation has sometimes – as in India – created conflicts with existing institutions, especially the government executive.

Because of their expertise and narrow focus, these new agencies may bring in economy, speed in decision-making, quick adaptation to change in conditions, and freedom from technicality and procedures. They can relax the formal rules of evidence when appropriate, to avoid over-reliance on adversarial techniques and to avoid strict adherence to their own precedence (Galligan-1996). The IRCs are thought not be as restricted to formulating decisions on a case-by-case basis as courts. As government expands into such unfamiliar territory in which complex factors have to be considered together, criteria that will adequately anticipate marginal cases become difficult to identify. Sometimes it is not possible to foresee what circumstances will arise. In these cases, a greater or lesser degree of discretionary powers may need to be left to the regulator, that is now the IRC. Rulemaking power is often found where regulation of highly complex nature is required. Delegation of rule-making power may also be needed where constant fine-tuning of rules and quick adaptation to meet new circumstances are required (Galligan-1996).

2.6 What is independence?

This is a somewhat misused and misunderstood term in the context of IRCs. There cannot be complete independence from government since the IRCs are also part of government. There can, however, the autonomy in functioning, especially in the performance of critical task like tariff regulation and determination. However, independence certainly cannot mean the absence of accountability. Further, the IRC cannot have total authority over all decisions to do with any issue including electricity. Even when the legislation and the policy enunciated by the government give the authority, the government might have legitimate concerns regarding law and order, public peace etc. The IRC must respond to public concerns and interests in performing its functions and objectives. The government must be in a position to ask the IRCs to take account of such concerns. The purpose of the degree of independence or autonomy given to the IRCs is to allow them to be seen as having a credible commitment to investors and consumers.

2.7 Independence and legitimacy

We must link independence to legitimacy. Independence is not an end in itself. The regulator must use what independence it has to establish its legitimacy as an objective body not influenced by any of the parties interested in the issue. It gives reasons for all its decisions after having engaged in the maximum possible consultation within all the uninterested parties. (Unfortunately, in that respect, it cannot be said that all ERCs in India have been legitimate. Legitimacy is largely a function of the capability of the members and their staff, but the Indian system of selections and deputations does not guarantee adequate capability.)

2.8 Regulatory powers of independent regulatory commissions

The regulatory powers exercised by the IRCs fall under three broad categories (Schwartz-1994).

1. **Licensing power** – The agency controls entry into the given economic activity. Thus, no airline may operate or extend its routes without a license from the Civil Aeronautics Board in the US or from the Civil Aviation Organisation in India. Similar authority over rail, motor, and water carriers and pipelines is given to the Interstate Commerce Commission in the US while there are government departments in India exercising similar powers.

2. **Rate-making power**- The agency possesses authority to fix the rates charged by utilities and such companies subject to its jurisdiction. Such authority is vested in the IRCs or government departments that regulate utilities and carriers.

3. **Power over business practices** – The agency is given authority to approve or prohibit practices employed in business.

2.9 Regulation of Electricity - International scenario

The process of electricity reforms can be said to have begun in world in the mid 1980s. The reforming countries can be broadly divided into three categories.

1) Those that were early reformers and where reforms have been consolidated to varying degrees (eg: Argentina, Australia, Chile, England, The US)

2) Those that started later and are now in transition (eg; Belgium, Brazil, Holland, Northern Ireland, Portugal, Scotland, Sweden)

3) Those that are formulating reform programmes or are in the early stages of implementation (eg: Germany, India, Peru, Russia, South Africa, Spain, Ukraine, Zambia) (Baijal – 1999)

2.10 Electricity Reform Models

Electricity reforms have followed three main models internationally. Australian model given below is a variant of the US model.

2.10.1 The US model

In this model, private-investor-owned utilities dominate electricity generation and other downstream activities. However, regulatory intervention (Public Utility Regulatory Policies Act, in the case of the US) has led to competition in the wholesale as well as retail markets and diminished this dominance. Due to the creation of vertically integrated geographical monopolies, the privately owned electricity sector in the US has been sheltered from competition and also criticized for being inefficient.

The main characteristics of this model are listed below:

- The generation and T&D (transmission and distribution) of electricity are vertically integrated.
- There is an established presence of independent power producers and trading in electricity.
- The presence of federal and state- government- owned utilities is minuscule (Grey-1996).
- Federal nature of the US rules this model. The states set their own development policies. The state utility commission establishes entry rules and incentives to bring in more competition and lower consumer prices.
- At the federal level, the FERC (Federal Electricity Regulatory Commission) sets prices in the US for interconnected transmission services.
- Transmission capacity in the US is inadequate as are interstate connections.
- Independent LDCs (Load Dispatch Centres) are owned by members of the system but inter-regional regulation is weak.

2.10.2 Australian Model

Initiated in Australia in the mid-1990s, electricity reforms have occurred at both the state and national levels. The national government has played a more activist role through the establishment of a national grid and a national pool (A pool for electricity refers to the equivalent of a stock exchange in financial markets. Since electricity is not identifiable like the scrip of a company, all electricity supplied and demanded is poled together and the LDC keeps track of who supplied how much and who drew how much). The national regulatory regime is light-handed and a form of priced regulation has been applied to the regulated sectors (Baijal-1999). The national electricity code establishes the regulatory and operational framework of the new electricity market and binds all participants in the wholesale power generation market to specified rules. The code addresses market rules, grid connection and access, metering, network pricing, system security, and procedures for code administration.

2.10.3 The UK Model

The UK has three separate and differently organized electricity markets.

1) England and Wales,
2) Scotland, and
3) Northern Ireland

The Electricity Act 1990 created the market system of England, Wales and Scotland. Before reforms, the Central Electricity Generating Board held the monopoly for generation and transmission. Area Boards had similar monopolies for distribution. Competition was introduced by separating generation, transmission, and distribution and by adding intermediary systems that allowed the cheapest generator to produce more by being able to sell more to the grid and by contracts between generators and large consumers. The success of the UK model is attributed to a well-structured and sequenced regulatory and unbundled system and the maturity of the restructured components that enhanced investor confidence in their potential profitability, thus increasing investment in the sector. This led to more competition and, consequently, greater efficiency.

2.10.4 The Latin American Model:

2.10.4.1 Chile :

Chile and Argentina are more or less identical as far as electricity regulation is concerned. There are four phases into which the reforms in Chile can be divided.

- Phase-I consisted of returning nationalized companies to their original owners
- Phase-II involved selling the nationalized companies for generation of revenues for the government.
- Phase-III was the stabilization phase
- Phase-IV initiated the power sector reforms (Baijal-1999).

While, prior to the reforms, the sector was mainly vertically integrated. It is now vertically segregated with competition in generation and supply. The restructuring allowed open entry to participation in the generation area, but without any supply or purchase obligations. New generators had to rely on the market for sale of their power. The LDC dispatches the system according to an economic merit order and determines SRMC (Short-run-marginal-cost) of the system. During t6hjue initial years, transmission remained a monopoly. Generators had right of access to the line if capacity was available, subject to payment of wheeling charges to be determined by the regulator. Distribution required a license that was granted under a competitive bidding system.

2.10.4.2 Peru

The Peru model consists of state-owned companies, which comprise the majority in generation, transmission, and bulk sale of electricity. This model is a late entrant in reforms race. Brazil may also be categorized under this model.

2.11 Power Sector reforms in India

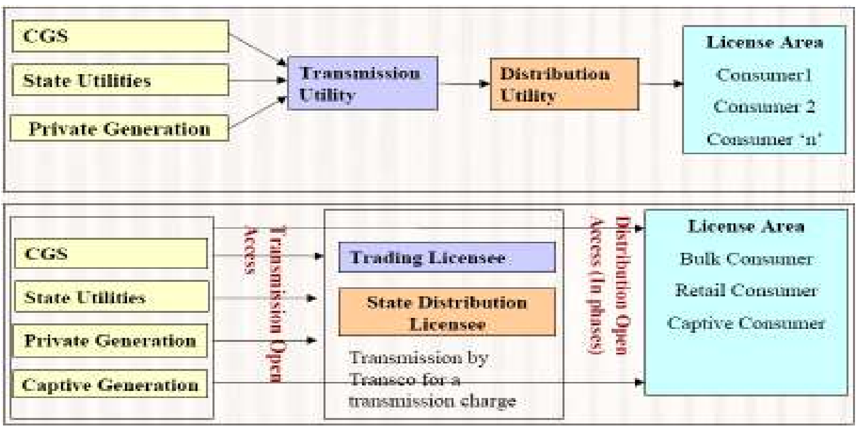
In 1991 Indian government launched systematic economic reforms programme. The infrastructure industries such as telecommunications and electricity have subsequently been restructured and opened to private sector participation. Accompanied with the restructuring and privatisation has been setting up of independent regulatory agencies for telecommunications and electricity. While there is a single Telecom Regulatory Authority of India (TRAI) for whole country, the electricity regulatory system in India is central and provincial. In addition to Central Electricity Regulatory Commission there are 26 other provincial (state level) State Electricity Regulatory Commissions (SERCs) that have been set up by the local (State) governments and union territories to regulate electricity markets, encourage competition and private investment. This is due to the federal nature of government in India and also because Indian constitution lists electricity in Concurrent List, meaning both the federal and state level governments are authorised to frame policies regarding electricity supply industry except for nuclear power which is in the domain of only federal government. Although most of the government owned state electricity boards are now unbundled and corporatised, there is little or no privatisation and the private sector investment in generation and distribution has been very little. A major cause for this could be lack of effective regulatory arrangements.

This session will examine the Indian electricity regulatory developments from an institutional economics perspective following Levy and Spiller (1994) and Stern and Holder (1999) framework to analyse the regulatory systems. While discussion will encompass issues at national level, a case of a particular state Gujarat will also be mentioned to map the regulatory developments in context of the institutional endowments and see whether that could explain the limited success of regulatory system in achieving the expected outcomes namely effective economic regulation and encouraging competition in the segments where it is possible.

Regulatory reforms in developed and developing countries accompanied with privatisation and deregulation of public utilities have generated substantial research interest in academic circles. The focus of much of the work on economic regulation has been on the instruments of regulation such as incentive regulation based on rate of return or price cap. Only recently the issues of the regulatory process and institutional arrangements have started attracting attention of the scholars. Levy and Spiller (1994) in their seminal paper argued that institutional aspects regulation need equal attention if the regulatory reform has to be effective in creating and sustaining environment for attracting and retaining private investment in the regulated industries. Institutional arrangements for practice of regulatory policy play a key role in providing stable and effective regulatory environment. Levy and Spiller (1994) provide empirical support for their arguments in their study of national institutional endowments and telecom regulatory institutions in five countries. Subsequently, the analytical framework has been used by Stern and Holder (1999) to study regulatory governance in developing countries of Asia. This study proposes to extend this work in Indian context with reference to electricity regulation. Stern and Holder (1999) did include electricity regulators in India in their study, but since 1999 there have been legislative changes as well as setting of many more state level regulatory commissions. Impacts of Electricity Act-2003 on pre and post electricity markets and power sector segments in India are self explanatory in Figure Nos. 2.1 & 2.2

Figure No.2.1

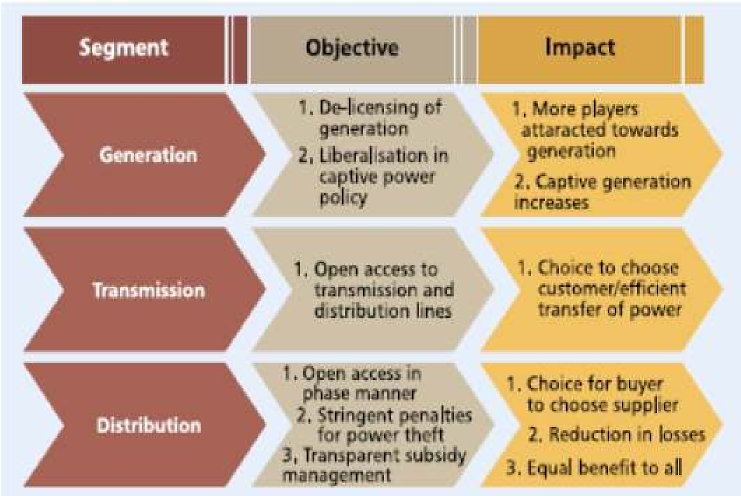
Pre and post EA 2003 Market design



Source: World Bank seminar on ' Indian power sector-Challenges and opportunities' New Delhi- 12 May 2006

Figure No.2.2

Segment-wise impact of Electricity Act-2003 in different segment of electricity



Source: D&B Industry Research Service

2.12 Institutional Framework Analysing Regulatory Structures

The privatisation and regulation experiment in the UK and many other countries is much-studied phenomenon. In most of the studies on economic regulation, the focus has been on instruments of regulatory policies such as price controls or rate of return. Earlier literature on regulation of US electricity, telecommunications and other regulated industries also show similar trends. As Levy and Spiller (1994) note that much of the literature on regulatory challenges concentrates on regulatory instruments such as incentive regulation.

Attempts by several economies in since 1980s to find market-based solutions to supply of infrastructure services have not been uniformly effective. Levy and Spiller (1994) argue that a nation's institutional endowments influence the regulatory design. Following North (1990) and others, a nation's institutional endowment is argued to comprise five elements:

1. Country's legislative and executive institutions
2. Country's judicial institutions

3. Customs and other informal but broadly accepted norms that are generally understood to constrain the action of individual or institution

4. Character of contending social interests within a society and the balance between them, including role of ideology.

5. Administrative capabilities of the nation

Through historical analysis of the regulatory structure in the broader contexts of the national institutional framework of their sample countries, Spiller and Levy highlight the interaction of political institutions with regulatory process and potential impact of such interaction on the regulatory performance. They analysed the regulatory designs of telecommunications industry in five countries (UK, Jamaica, Philippines, Argentina and Chile). They argue that, "the credibility and effectiveness of a regulatory framework and hence its ability to facilitate private investment varies with a country's political and social institutions." (Spiller and Levy, 1994, p.202). Therefore, of the five elements of national institutional endowments listed by North (1990), Spiller and Levy concentrate on the first two elements in their study. They conclude, "that success of regulatory systems depends on how well it fits with a country's prevailing institutions, if a country lacks the requisite institutions or regulatory system that is incompatible with its institutional endowment, efforts at privatization may end in disappointment, recriminations, and the resurgence of demands for re-nationalisation." (Spiller and Levy, 1994, p. 242).[3]

Spiller and Levy's study makes another important contribution by providing an analytical framework to study the regulatory governance separately. They identify regulatory design as comprising of two elements namely regulatory governance and regulatory incentives. They define regulatory governance as, "governance structure of a regulatory system as the mechanism that societies use to constrain regulatory discretion and to resolve conflicts that arise in relation to these constraints." (p. 205).

[3]Levy, B and P.T. Spiller (1994) The Institutional Foundations of Regulatory Commitment: A Comparative Analysis of Telecommunication Regulation, *Journal of Law Economics and Organisation,* V 10, No. 2, 201-246.

Regulatory incentives on other hand comprise the rules governing utility pricing, cross or direct subsidies, entry, interconnections etc.

Stern and Holder (1997)[4] extend the study of regulatory systems but concentrate on the regulatory process in addition to Levy and Spiller's focus on institutional design and formal accountability of regulatory institutions. Stern (1997) focuses on issues of informal accountability, which are listed by North as points 3 and 4 above. Explaining the distinction between the formal and informal accountability, Stern and Holder (1997) split the attributes of institutional framework into two categories. They describe formal institutional mechanisms that are written in the legislation and informal mechanisms as regulatory process encompassing the implementation of the regulatory laws. The later process involves interpretation and understanding of law among the stakeholders (namely regulators, regulated participants and consumers).

Stern and Holder (1997) identify six inter related aspects of regulatory framework and provide results from a survey of regulatory practice for infrastructure industries in Asian countries. Three of the six aspects relate to institutional design (the formal accountability) and other three relate to regulatory process and practices (informal accountability). The formal accountability aspects include:

- Clarity of Roles and Objectives
- Autonomy
- Accountability

The informal accountability aspects studied are:

- Participation
- Transparency, and
- Predictability.

[4] Stern, J, S Holder (1999) Regulatory governance: Criteria for assessing the performance of regulatory systems - An application to infrastructure industries in the developing countries of Asia. *Utilities Policy*, 33-50.

Stern and Holder report the results of a survey of a twelve infrastructure industries in six developing countries from Asia namely, Bangladesh, India, Indonesia, Malaysia, Pakistan and Philippines. Regulatory arrangements were appraised on above-mentioned aspects of regulatory accountability against an 'international best practice', which authors develop based on regulatory experience in OECD countries. The definitions used for best practice by Stern and Holder (1999) are given below:

2.13

CHAPTER 3

WORLD ENERGY DEMAND AND ECONOMIC OUTLOOK

3.1 Introduction

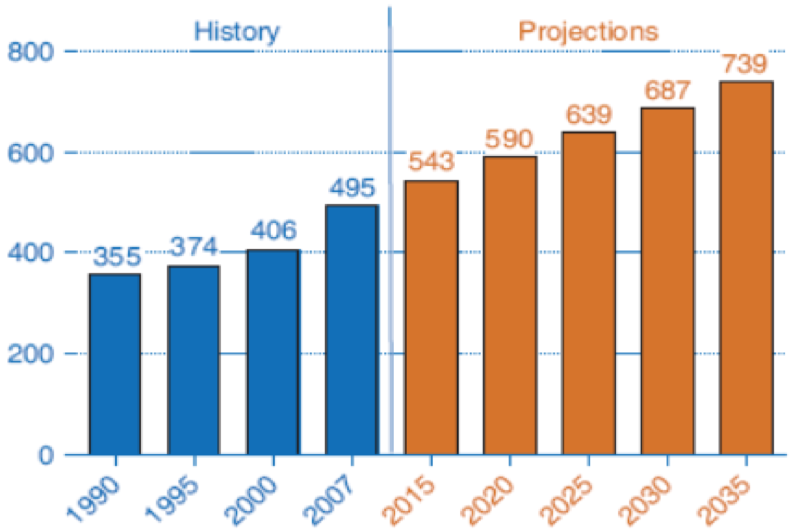
In the International Energy Outlook-2010 *(IEO-2010)* projections, world energy consumption increases by 49 percent, or 1.4 percent per year, from 495 quadrillion Btu in 2007 to 739 quadrillion Btu in 2035 (Figure 3.1 and Table 3.1). The global economic recession that began in 2008 and continued into 2009 had a profound impact on world income (as measured by GDP) and energy use. After expanding at an average annual rate of 4.9 percent from 2003 to 2007, worldwide GDP growth slowed to 3.0 percent in 2008 and contracted by 1.0 percent in 2009. Similarly, growth in world energy use slowed to 1.2 percent in 2008 and then declined by an estimated 2.2 percent in 2009.

Global economic recovery from the recession has been uneven so far. Developing non-OECD Asian economies have led the global recovery, and many are already out of recession. While there are indications that the recession in the United States has ended, recovery in Europe and Japan has lagged. The *IEO2010* assumes that, by 2015, most nations of the world will have resumed their expected rates of long-term growth before the recession. World GDP rises by an average of 3.2 percent per year from 2007 to 2035 in the reference case, with non-OECD economies averaging 4.4 percent per year and OECD economies 2.0 percent per year.

Historically, OECD member countries have accounted for the largest share of current world energy consumption; however, in 2007 - for the first time - energy use among non-OECD nations exceeded that among OECD nations (Figure 3.2). The discrepancy between OECD and non-OECD energy use grows in the future, given the more rapid growth in energy demand expected for the emerging non-OECD economies. In 2007, energy use in non-OECD nations was 1.5 percent higher than that in OECD nations. In the *IEO2010*, non-OECD economies consume 32 percent more energy than OECD economies in 2020 and 63 percent more in 2035. OECD energy use grows slowly over the projection period, averaging 0.5 percent per year from 2007 to 2035, as compared with 2.2 percent per year for the emerging non-OECD economies.

Figure No. 3.1

World marketed energy consumption , 1990-2035 (quadrillion Btu)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

Table No. 3.1

World marketed energy consumption by country grouping, 2007-2035(quadrillion Btu)

Region	2007	2015	2020	2025	2030	2035	Average annual percent change, 2007-2035
OECD	**245.7**	**246.0**	**254.2**	**263.2**	**271.4**	**280.7**	**0.5**
North America	123.7	124.3	129.4	134.9	140.2	146.3	0.6
Europe	82.3	82.0	83.0	85.0	86.5	88.2	0.2
Asia	39.7	39.7	41.8	43.3	44.8	46.3	0.5
Non-OECD	**249.5**	**297.5**	**336.3**	**375.5**	**415.2**	**458.0**	**2.2**
Europe and Eurasia	51.5	52.4	54.2	56.2	57.8	60.2	0.6
Asia	127.1	159.3	187.8	217.0	246.9	277.3	2.8
Middle East	25.1	32.9	36.5	39.1	41.8	45.7	2.2
Africa	17.8	20.8	22.5	24.6	26.5	29.0	1.8
Central and South America	28.0	32.1	35.5	38.7	42.2	45.7	1.8
Total World	**495.2**	**543.5**	**590.5**	**638.7**	**686.5**	**738.7**	**1.4**

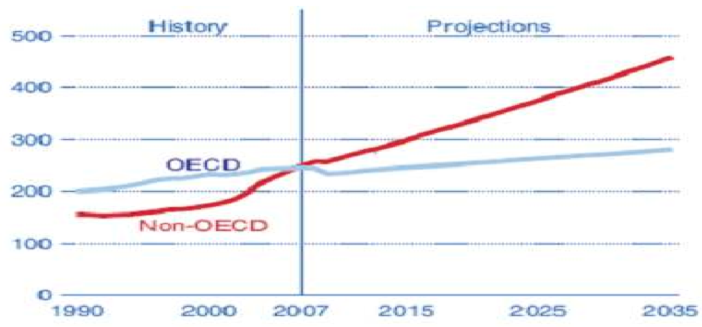
Source: U.S. Energy Information Administration / International Energy Outlook 2010

Two nations that were among the least affected by the global recession were China and India, and they continue to lead the world's economic growth and energy demand growth in the Reference case. Since 1990, energy consumption as a share of total world energy use has increased significantly in both countries, and together they accounted for about 10 percent of the world's total energy consumption in 1990 and 20 percent in 2007. Strong economic growth in both countries continues over the projection period, with their combined energy use more than doubling and accounting for 30 percent of total world energy consumption in 2035 in the Reference case. In contrast, the U.S. share of world energy consumption falls from 21 percent in 2007 to about 16 percent in 2035 (Figure 3.3).

Energy use in non-OECD Asia (led by China and India) shows the most robust growth of all the non-OECD regions, rising by 118 percent from 2007 to 2035 (Figure 3.4 15). However, strong growth in energy use also is projected for much of the rest of the non-OECD regions. With fast-paced growth in population and access to rich resources, energy demand in the Middle East increases by 82 percent over the projection period. In Central and South America and Africa, energy consumption increases by 63 percent. The slowest projected growth among non-OECD regions is for non-OECD Europe and Eurasia, which includes Russia and the other former Soviet Republics. Growth in energy use for the region totals 17 percent from 2007 to 2035, as its population declines and substantial gains in energy efficiency are achieved through the replacement of inefficient Soviet era Capital equipment.

Figure 3.2

World marketed energy consumption: OECD and Non – OECD, 1990-2035 (quadrillion BTU)



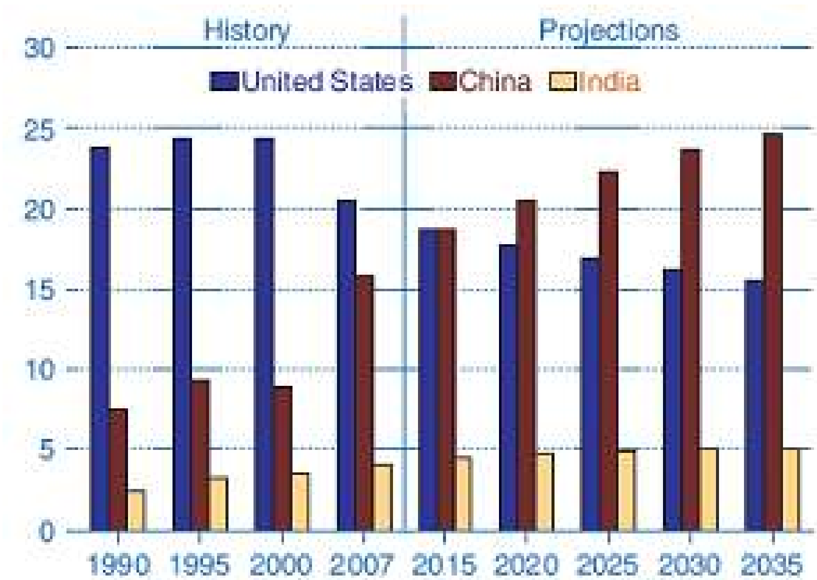
Source: U.S. Energy Information Administration / International Energy Outlook 2010

This chapter presents an overview of the *IEO2010* outlook for global marketed energy consumption by energy source. It also includes discussions of the major assumptions that form the basis for the *IEO2010* projections, including macroeconomic assumptions for the key OECD and non-OECD regions. As with any set of projections, there is significant uncertainty associated with the *IEO2010* energy projections. Two sets of sensitivity cases, which vary some of the assumptions behind the projections, are also examined in this chapter viz. the High Economic Growth and Low Economic Growth cases and the High Oil Price and Low Oil Price cases. The sensitivity cases are intended to illustrate alternative scenarios. They are not intended to identify any bounds on uncertainty, which can also be affected by policy and technology developments in addition to world oil price and economic growth paths.

Figure 3.3.

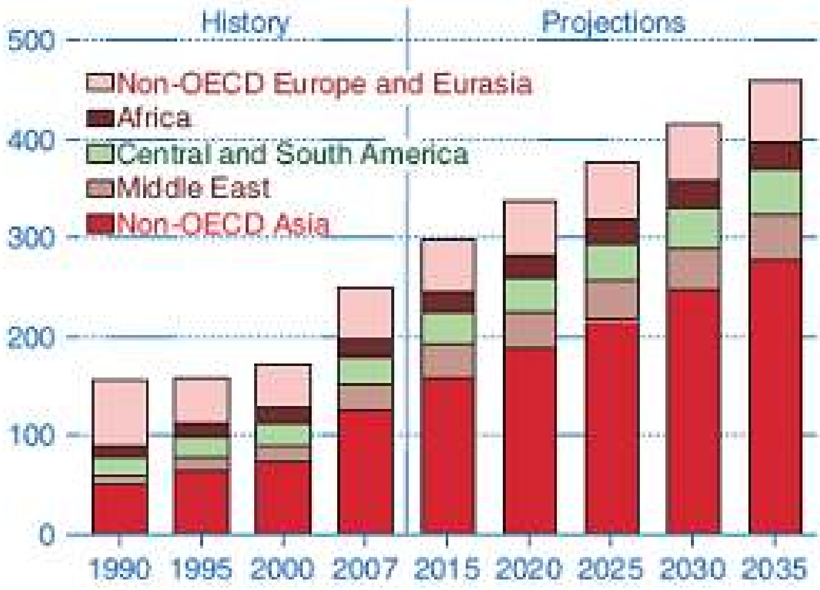
Shares of world energy consumption in the US, China, and India.1990-2035

(Percent of world total)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

Figure 3.4.
Marketed energy use in Non-OECD economies by region, 1990-2035
(Percent of world total)



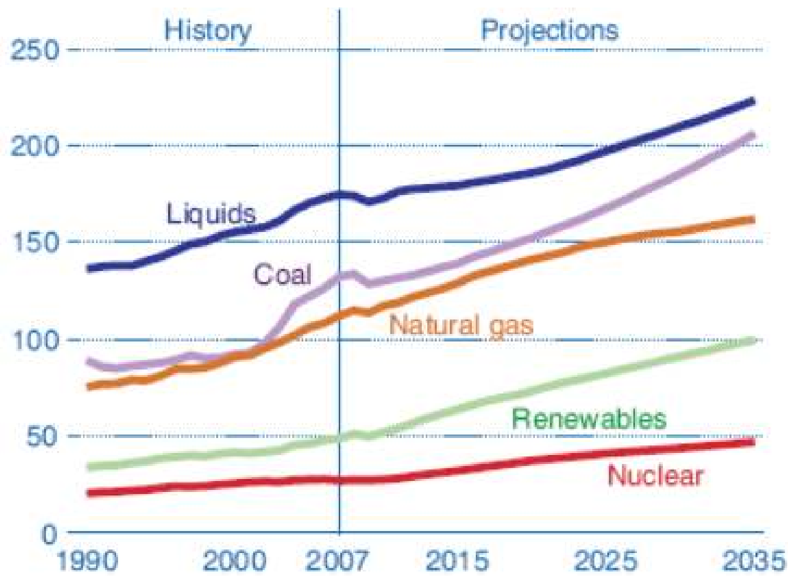
Source: U.S. Energy Information Administration / International Energy Outlook 2010

3.2 Outlook for world energy consumption by source

The use of all energy sources increases over the time horizon of the *IEO2010* Reference case (Figure 3.5). Given expectations that world oil prices will remain relatively high through most of the projection period, liquid fuels and other petroleum are the world's slowest-growing source of energy. Liquids consumption increases at an average annual rate of 0.9 percent from 2007 to 2035, whereas total energy demand increases by 1.4 percent per year. Renewables are the fastest-growing source of world energy, with consumption increasing by 2.6 percent per year. Projected oil prices, as well as concern about the environmental impacts of fossil fuel use and strong government incentives for increasing the use of renewable energy in many countries around the world, improve the prospects for renewable energy sources worldwide in the outlook.

Although liquid fuels are expected to remain the largest source of energy, the liquids share of world marketed energy consumption declines from 35 percent in 2007 to 30 percent in 2035. On a worldwide basis, the use of liquids remains flat in the building sector and increases modestly in the industrial sector. In the electric power sector, the use of liquids declines as electricity generators react to steadily rising world oil prices by switching to alternative fuels whenever possible. Liquids use in the transportation sector, in contrast, continues to increase despite the rising world oil prices in the Reference case. World liquids consumption for transportation grows by 1.3 percent per year in the Reference case, and in the absence of significant technological advances, liquids continue to dominate the world's transportation markets through 2035.

Figure 3.5.
World marketed energy use by fuel type, 1990-2035 (quadrillion Btu)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

Natural gas remains an important fuel for electricity generation worldwide. Electricity generation is less expensive with natural gas than with oil as the primary energy source, and natural-gas-fired generating plants are less capital-intensive than plants that use coal, nuclear, or most renewable energy sources. In the *IEO2010* Reference case, the world's total natural gas consumption increases by 1.3 percent per year on average, from 108 trillion cubic feet in 2007 to 156 trillion cubic feet in 2035, and its use in the electric power sector increases by 1.6 percent per year.

High world oil prices encourage consumers to turn to natural gas in the near future, but as supplies of natural gas become increasingly expensive to produce after 2020, the growth of natural gas use slows substantially. Between 2007 and 2020, worldwide natural gas demand increases by 1.8 percent per year, but between 2020 and 2035 the rate of growth is only 0.9 percent per year, as consumers turn to alternative sources of generation - notably, renewable energy sources, nuclear power, and, in the absence of policies that would limit its use, coal. World coal consumption increases by 1.6 percent per year on average from 2007 to 2035, but most of the growth in demand occurs after 2020. Worldwide coal consumption increased by 35 percent between 2002 and 2007; largely because of the growth in China's coal use.

Between 2007 and 2009, however, coal consumption declined by 3 percent. Coal use was strongly affected by the global recession, and consumption contracted strongly in 2009, in large part because coal is widely used in the production of heavy commodities (such as, steel and pig iron), which were particularly hard hit in the recession.

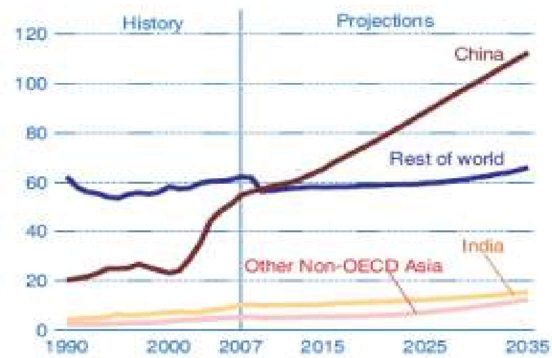
In the absence of policies or legislation that would limit the growth of coal use, China and, to a lesser extent, India and the other nations of non-OECD Asia consume coal in place of more expensive fuels. China alone accounts for 78 percent of the net increase in world coal consumption, whereas India and the rest of non-OECD Asia combined account for 17 percent of the world increase (Figure 3.6).

Electricity is the world's fastest-growing form of endues energy consumption in the Reference case, as it has been for the past several decades. Net electricity generation worldwide rises by 2.3 percent per year on average from 2007 to 2035, while total world energy demand grows by 1.4 percent per year. The strongest growth in electricity generation is for non-OECD countries.

Non-OECD electricity generation increases by an average annual rate of 3.3 percent in the Reference case, as rising standards of living increase demand for home appliances and the expansion of commercial services, including hospitals, office buildings, and shopping malls. In OECD nations, where infrastructures are more mature and population growth is relatively slow, growth in generation is much slower, averaging 1.1 percent per year from 2007 to 2035. Coal provides the largest share of world electricity generation in the Reference case. It accounted for 42 percent of total generation in 2007, and its share is largely unchanged through 2035 (Figure 3.7). In contrast, liquids, natural gas, and nuclear power all lose market share of world generation over the course of the projection period, displaced by the strong growth projected for renewable sources of generation. Renewable generation is the world's fastest-growing source of electric power in the *IEO2010* Reference case, rising at an average annual rate of 3.0 percent over the projection period, as compared with increases of 2.3 percent per year for coal, 2.1 percent per year for natural gas, and 2.0 percent per year for nuclear power. With government policies and incentives throughout the world supporting the rapid construction of renewable generation facilities, the renewable share of world generation increases from 18 percent in 2007 to 23 percent in 2035.

Figure 3.6

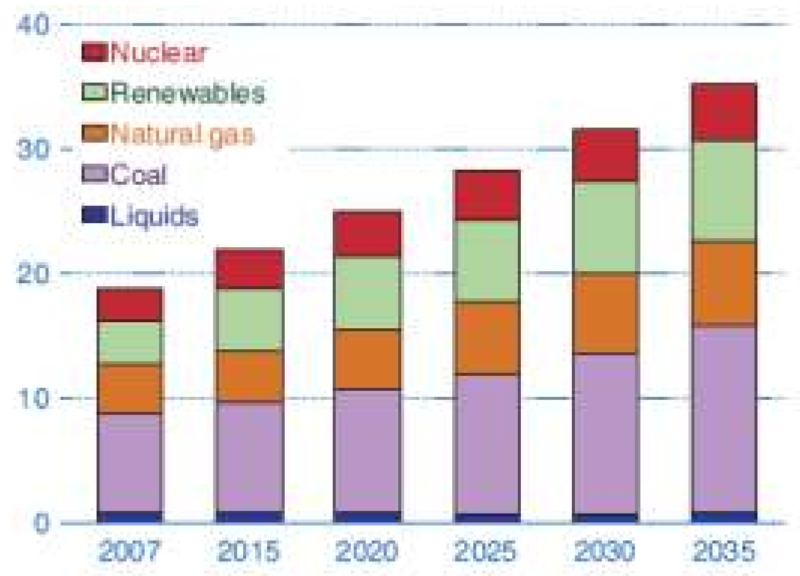
Coal consumption in selected world regions, 1990-2035 (quadrillion Btu)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

Figure 3.7

World electricity generation by fuel, 2007-2035 (trillion kilo watt hours)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

Worldwide, hydroelectricity and wind provide the largest shares of the projected increase in total renewable generation, accounting for 54 percent and 26 percent of the total increment, respectively. The relative mix of fuels in the OECD and non-OECD regions, however, differs dramatically. In OECD nations, the majority of economically exploitable hydroelectric resources already have been developed. With the exception of Canada and Turkey, there are few large-scale hydroelectric power projects planned for the future. Instead, most renewable energy growth in OECD countries is expected to come from non-hydroelectric sources, especially wind. Many OECD countries, particularly those in Europe, have government policies (including feed-in tariffs, tax incentives, and market-share quotas) that encourage the construction of wind and other no hydroelectric renewable electricity facilities.

In non-OECD nations, hydroelectric power is the predominant source of renewable energy growth. Strong increases in hydroelectric generation, primarily from mid- to large-scale power plants, are expected in Brazil and in non-OECD Asia (especially, China and India), which in combination account for 83 percent of the total increase in non-OECD hydroelectric generation over the projection period. Growth rates for wind-powered electricity generation also are high in non-OECD countries.

The fastest-growing non-OECD regional market for wind power is attributed to China, where total generation from wind power plants increases from 6 billion kilowatt-hours in 2007 to 374 billion kilowatt-hours in 2035. Still, the total increase in China's wind-powered generation is less than half the increase in its hydroelectric generation (Figure 3.8).

Electricity generation from nuclear power worldwide increases from 2.6 trillion kilowatt-hours in 2007 to 4.5 trillion kilowatt-hours in 2035 in the *IEO2010* Reference case, as high fossil fuel prices and concerns about energy security and greenhouse gas emissions support the development of new nuclear generating capacity. World average capacity utilization rates have continued to rise over time, from about 65 percent in 1990 to about 80 percent today, with some increases still anticipated in the future. In addition, most of the older plants now operating in OECD countries and in non-OECD Eurasia probably will be granted extensions to their operating licenses.

Nuclear power, however, and a number of issues could slow the development of new nuclear power plants. Plant safety, radioactive waste disposal, and nuclear material proliferation concerns, which continue to raise public concerns in many countries, may hinder plans for new installations, and high capital and maintenance costs may keep some countries from expanding their nuclear power programs.

Nearly 72 percent of the world expansion in installed nuclear power capacity is expected in non-OECD countries (Figure 3.9). China, India, and Russia account for the largest increment in world net installed nuclear power between 2007 and

2035. In the Reference case, China adds 66 GW (gigawatts) of nuclear capacity between 2007 and 2035, India 23 gigawatts, and Russia 25 gigawatts. Within the OECD, every region increases its installed nuclear capacity to some extent, except for Australia and New Zealand, where existing policies that discourage nuclear power are assumed to remain unchanged through the end of the projection period.

In a change from past *IEOs*, OECD Europe sees an increase in nuclear power capacity over the projection period, as a number of European countries have reassessed their nuclear stance in the past year. The governments of several countries have announced changes in their positions since 2009, including the Belgian government, which decided to delay its phase out plans by 10 years; the German government, which has expressed willingness to reconsider its nuclear phase out policies; and the Italian government, which has formally ended its anti-nuclear policies and announced plans for constructing a new reactor by 2020. There are also indications that several other European countries, including Poland and Turkey, plan to begin new nuclear generation programs. In the *IEO-2010*, OECD Europe adds a net 10 gigawatts of installed nuclear capacity between 2006 and 2030, as compared with a net loss of 11 gigawatts of nuclear capacity projected in *IEO2009*.

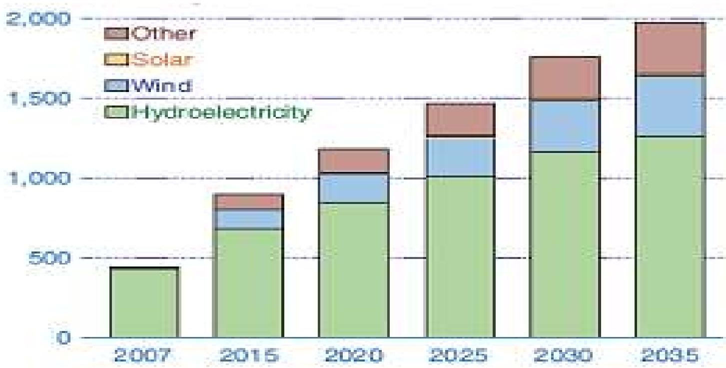
In the United States, Title XVII of the Energy Policy Act of 2005 (EPACT2005, Public Law 109-58) authorizes the U.S. Department of Energy to issue loan guarantees for innovative technologies that "avoid, reduce, or sequester greenhouse gases". In addition, subsequent legislative provisions in the Consolidated Appropriation Act of 2008 (Public Law 110-161) allocated $18.5 billion in guarantees for nuclear power plants. That legislation, along with high fossil fuel prices, results in increases of 8.4 gigawatts of capacity at newly built U.S. nuclear power plants between 2007 and 2035 and 4.0 gigawatts from expansion projects at existing plants. All existing U.S. nuclear units continue to operate through 2035 in the Reference case, which assumes that the owners will apply for and receive operating license renewals including, in some cases, a second extension after they reach 60 years of operation.

3.3 Delivered energy consumption by end-use sector

Understanding patterns in the consumption of energy delivered to end users is important to the development of projections for global energy use. Outside the transportation sector, which at present is dominated by liquid fuels, the mix of energy use in the residential, commercial, and industrial sectors varies widely by region, depending on a combination of regional factors, such as the availability of energy resources, levels of economic development, and political, social, and demographic factors.

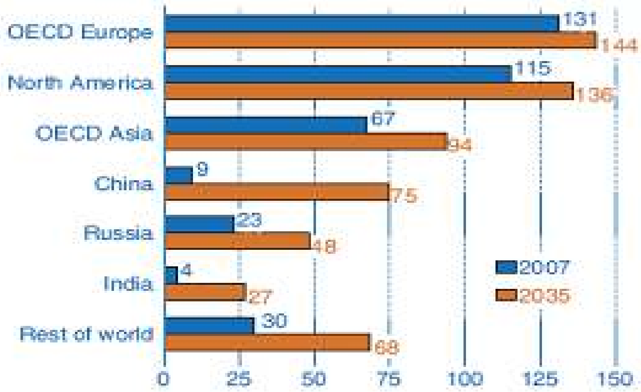
Figure 3.8

Renewable electricity generation in China by energy source, 2007-2035 (billion Kilowatt-hours)



U.S. Energy Information Administration / International Energy Outlook 2010

Figure3.9
World nuclear generating capacity by region,2007 and 2035 (gigawatts)



U.S. Energy Information Administration / International Energy Outlook 2010

3.3.1 Residential sector

Energy use in the residential sector, which accounted for about 14 percent of world delivered energy consumption in 2007, is defined as the energy consumed by households, excluding transportation uses. Residential energy use grows at an average rate of 1.1 percent per year from 2007 to 2035. The type and amount of energy used by households vary from country to country, depending on income levels, natural resources, climate, and available energy infrastructure. In general, typical households in OECD nations use more energy than those in non-OECD nations, in part because higher income levels allow OECD households to have larger homes and purchase more energy-using equipment. In the United States, for example, GDP per capita in 2007 was $43,076 , and residential energy use per capita was estimated at 37.2 million Btu. In contrast, China's per-capita income in 2007, at $5,162, was only about one-eighth the U.S. level, and its residential energy use per capita, at 4.0 million Btu, was about one-ninth the U.S. level. For residential buildings, the physical size of a structure is one key indicator of the amount of energy used by its occupants, although income level and a number of other factors, such as weather, can also affect the amount of energy consumed per household. Controlling for those factors, larger homes generally require more energy to provide heating, air conditioning, and lighting, and they tend to include more energy-using appliances, such as televisions and laundry equipment. Smaller structures usually require less energy, because they contain less space to be heated or cooled, produce less heat transfer with the outdoor environment, and typically have fewer occupants. For instance, residential energy consumption is lower in China, where the average residence currently has an estimated 300 square feet of living space or less per person, than in the United States, where the average residence has an estimated 680 square feet of living space per person.

Although the *IEO2010* projections account for marketed energy use only, households in many non-OECD countries still rely heavily on traditional, non-marketed energy sources, including wood and waste, for heating and cooking. Much of Africa remains unconnected to power grids, and the International Energy Agency estimates that more than 70 percent of the sub-Saharan African population does not have access to electricity. About 37 percent of the world population - largely in India and Africa - still relies on animal dung, fuel wood, and agricultural residues for cooking fuel. Some areas of China and India also rely heavily on fuel wood, wood waste, and charcoal for cooking. As incomes rise in the developing world over the course of the projection, households replace the use of traditional fuels with marketed ones, such as propane and electricity, as they become more widely accessible.

3.3.2Commercial sector

The commercial sector - often referred to as the service sector or the services and institutional sector - consists of businesses, institutions, and organizations that provide services. The sector, which accounted for 7 percent of total delivered energy consumption in 2007, encompasses many different types of buildings and a wide range of activities and energy-related services. Commercial sector energy use grows by an average of 1.5 percent per year from 2007 to 2035. Examples of commercial sector facilities include schools, stores, correctional institutions, restaurants, hotels, hospitals, museums, office buildings, banks, and sports arenas. Most commercial energy use occurs in buildings or structures, supplying services such as space heating, water heating, lighting, cooking, and cooling. Energy consumed for services not associated with buildings, such as for traffic lights and city water and sewer services, is also categorized as commercial energy use.

Economic trends and population growth drive commercial- sector activity and the resulting energy use. The need for services (health, education, financial, and government) increases as populations increase. The degree to which additional needs are met depends in large measure on economic resources whether from domestic or foreign sources and economic growth. Economic growth also determines the degree to which additional activities are offered and used in the commercial sector. Higher levels of economic activity and disposable income lead to increased demand for hotels and restaurants to meet business and leisure requirements; for office and retail space to house and service new and expanding businesses; and for cultural and leisure space such as theaters, galleries, and arenas. In the commercial sector, energy intensity or energy use per dollar of income as measured by GDP in non-OECD countries is much lower than in OECD countries. Non-OECD commercial energy intensity in 2007, at 281 Btu per dollar of GDP, was only about half the OECD level (522 Btu per dollar of GDP).

In the future, slower expansion of GDP and low or declining population growth in many OECD nations contribute to slower anticipated rates of increase in commercial energy demand. In addition, continued efficiency improvements moderate the growth of energy demand over time, as energy-using equipment is replaced with newer, more efficient stock. Conversely, continued economic growth is expected to include growth in business activity, with its associated energy use, in areas such as retail and wholesale trade and business, financial services, and leisure services. The United States is the largest consumer of commercial delivered energy in the OECD and remains in that position throughout the projection, accounting for about 45 percent of the OECD total in 2035.

In non-OECD nations, economic activity and commerce increase rapidly, fueling additional demand for energy in the service sectors. Population growth also is more rapid than in OECD countries, portending increases in the need for education, health care, and social services and the energy required to provide them. In addition, as developing nations mature, they transition to more service- related enterprises, increasing demand for energy in the commercial sector. The energy needed to fuel growth in commercial buildings will be substantial, with total delivered commercial energy use among non-OECD nations growing by 2.7 percent per year from 2007 to 2035.

3.3.3 Industrial sector

Energy is consumed in the industrial sector by a diverse group of industries - including manufacturing, agriculture, mining, and construction - and for a wide range of activities, such as processing and assembly, space conditioning, and lighting. The industrial sector comprised 51 percent of global delivered energy use in 2007 and grows by an average annual 1.3 percent over the projection. Industrial energy demand varies across regions and countries of the world, based on the level and mix of economic activity and technological development, among other factors. Industrial energy use also includes natural gas and petroleum products used as feedstocks to produce non-energy products, such as plastics and fertilizer. In aggregate, the industrial sector uses more energy than any other end-use sector, consuming about one-half of the world's total delivered energy.

OECD economies generally have more energy-efficient industrial operations and a mix of industrial output that is more heavily weighted toward non-energy-intensive sectors than the mix in non-OECD countries. As a result, the ratio of industrial energy consumption to total GDP tends to be higher in non-OECD economies than in OECD economies. On average, industrial energy intensity (the consumption of energy consumed in the industrial sector per dollar of economic output) in non-OECD countries is double that in OECD countries.

3.3.4 Transportation sector

Energy use in the transportation sector includes the energy consumed in moving people and goods by road, rail, air, water, and pipeline. The transportation sector accounted for 27 percent of total world delivered energy consumption in 2007, and transportation energy use increases by 1.3 percent per year from 2007 to 2035. The road transport component includes light-duty vehicles, such as automobiles, sport utility vehicles, minivans, small trucks, and motorbikes, as well as heavy-duty vehicles, such as large trucks used for moving freight and buses used for passenger travel. Growth rates for economic activity and population are the key factors for transportation energy demand. Economic growth spurs increases in industrial output, which requires the movement of raw materials to manufacturing sites, as well as the movement of manufactured goods to end users.

For both non-OECD and OECD economies, steadily increasing demand for personal travel is a primary factor underlying projected increases in energy demand for transportation. Increases in urbanization and in personal incomes have contributed to increases in air travel and motorization (more vehicles per capita) in the growing economies. Increases in the transport of goods result from continued economic growth in both OECD and non-OECD economies. For freight transportation, trucking leads the growth in demand for transportation fuels. In addition, as trade among countries increases, the volume of freight transported by air and marine vessels increases rapidly.

3.4 World economic outlook

Economic growth is among the most important factors to be considered in projecting changes in world energy consumption. In *IEO2010*, assumptions about regional economic growth measured in terms of real GDP in 2005 U.S. dollars at purchasing power parity rates underlie the projections of regional energy demand. Starting in 2008, the world experienced its worst recession of the past 60 years. Although it appears that recovery has begun, its strength and timing are not entirely clear. The emerging economies of Asia (led by China and India) appear to be recovering quickly. The advanced economies, particularly the European countries and Japan, are improving much more slowly and have had concerns about a return to recession in the short term.

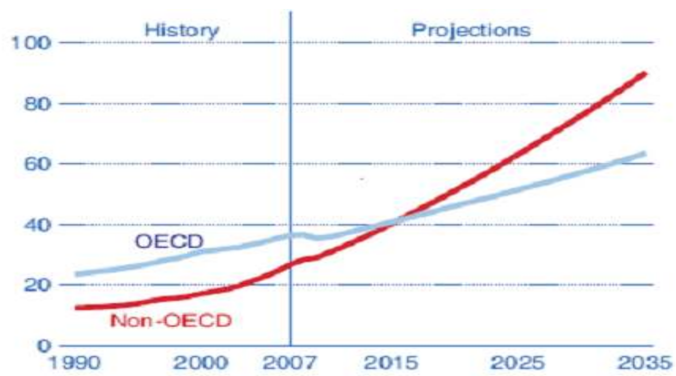
Substantial stimulus packages in the United States and China, as well as in a number of other countries around the world, are widely credited with averting another Great Depression. China's $586 billion stimulus package has been used largely to fund infrastructure projects (including railways, roads, airports, urban power grids, and irrigation projects) and also for social programs, both domestically and abroad. Many non-OECD Asian economies that are trading partners with China also have benefited from their ties with China. The emerging Asian economies - particularly those strongly dependent on exports for revenues - saw profound decreases in economic activity in 2008 and into 2009, as demand for goods among OECD economies declined sharply. The recovery in China has bolstered their recovery. From 2007 to 2035, growth in world real GDP (on a purchasing power parity basis) averages 3.2 percent per year in the Reference case (Table 3.2). In the long term, the ability to produce goods and services (the supply side) determines the growth potential of each country's economy.

Growth potential is influenced by population growth, labor force participation rates, capital accumulation, and productivity improvements. In addition, for the developing economies, progress in building human and physical capital infrastructures, establishing credible regulatory mechanisms to govern markets, and ensuring political stability also are important determinants of medium- to long-term growth potential.

Annual growth in world GDP over the 28-year projection period in *IEO2010* (3.23 percent per year) is about the same as the rate recorded over the past 30 years (3.25 percent per year). Growth in the more mature industrialized economies of the OECD is expected to be slower, and growth in the emerging non-OECD economies is projected to be higher, than in the past. The combined GDP of OECD countries, which increased by an annual average of 2.9 percent from 1977 to 2007, averages 2.0 percent per year from 2007 to 2035. In contrast, the combined GDP of non-OECD countries, which increased by an annual average of 3.7 percent from 1977 to 2007, averages 4.4 percent per year growth from 2007 to 2035, based in a large part on the strong growth projected for China and India. With non-OECD economies accounting for an increasing share of world GDP, their more rapid economic growth rates offset the slower growth rates for OECD economies in the Reference case (Figure 3.10).

Figure 3.10

OECD and Non OECD total Gross domestic product, 1990-2035
(trillion 2005 U.S. dollars)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

3.4.1 OECD economies

In the *IEO2010 review*, overall OECD economic growth averages 2.0 percent per year and U.S. GDP growth averages 2.4 percent per year from 2007 to 2035. The U.S. recession, which began in December 2007, is the longest of the 10 recessions the United States has experienced since 1947, with four quarters of negative growth. It was also the country's deepest recession since 1957. In 2009, U.S. GDP declined by 2.4 percent, and in 2010 it is expected to increase at a considerably slower rate than the annual average of 2.9 percent over the past two decades.

Table 3.2.

World gross product by country grouping, 2007-2035 (billion 2005 dollars, purchasing power parity)

Region	2007	2015	2020	2025	2030	2035	Average annual percent change, 2007-2035
OECD	**36,361**	**40,819**	**46,146**	**51,492**	**57,260**	**63,480**	**2.0**
North America	15,662	18,081	21,023	24,072	27,445	31,142	2.5
Europe	14,849	16,208	18,035	19,864	21,771	23,807	1.7
Asia	5,850	6,530	7,089	7,557	8,044	8,531	1.4
Non-OECD	**26,769**	**40,301**	**51,286**	**63,247**	**76,179**	**90,179**	**4.4**
Europe and Eurasia	3,481	4,193	4,940	5,731	6,557	7,440	2.7
Asia	14,323	24,055	31,832	40,307	49,366	59,023	5.2
Middle East	2,261	3,071	3,742	4,473	5,336	6,328	3.7
Africa	2,638	3,639	4,406	5,221	6,102	7,094	3.6
Central and South America	4,066	5,343	6,366	7,516	8,818	10,294	3.4
Total World	**63,130**	**81,120**	**97,433**	**114,740**	**133,439**	**153,658**	**3.2**

Source: IHS Global Insight and EIA.

U.S. Energy Information Administration / International Energy Outlook 2010

The U.S. economic recovery is expected to intensify in 2011, with employment recovering more slowly. As a result, real GDP returns to its 2007 prerecessionary level by 2011, but employment rates do not return to 2007 levels until 2019. Canada was also affected substantially by the world recession, with GDP contracting by 2.3 percent in 2009. The strong trade ties between Canada and the United States mean that weak U.S. economic growth, coupled with a relatively strong (by historical standards) Canadian dollar, helped lead Canada into economic recession. Like many countries in the industrialized world, Canada instituted a substantial 2-year stimulus-spending program in early 2009 - about $30 billion or 1.9

percent of GDP - for infrastructure improvements, income tax reductions, and housing construction incentives, among other programs.

The Canadian economy showed signs of recovery at the end of 2009, with 5.0-percent GDP growth in the fourth quarter. In 2010, the government announced plans to phase out stimulus spending by March 2011 and, through budget austerity measures, to cut Canada's $54 billion deficit in half within 2 years. In the long term, as U.S. consumer demand returns and export markets improve, economic growth in Canada returns to its potential. In the IEO2010 Reference case, Canada's GDP grows by an average of 2.1 percent per year from 2007 to 2035.

Mexico was the Western Hemisphere's hardest-hit economy in the 2008-2009 recession. Not only did it suffer when worldwide commodity exports collapsed, but the impact of the recession was compounded by the outbreak of H1N1 "swine flu" in 2009. Mexico's high reliance on the United States as a market for its manufacturing exports suggests that its economic recovery will be dependent on the U.S. recovery. About 80 percent of Mexico's exports are sent to the United States. Rising world oil prices and recovery of the U.S. economy are expected to support Mexico's return to trend growth, with GDP increasing by an average of 3.5 percent per year from 2007 to 2035.

In 2009, GDP in the economies of OECD Europe contracted by 3.9 percent, much more sharply than the 0.2-percent decline anticipated in last year's *IEO*. In 2010, economic growth in OECD Europe is expected to average only 1.0 percent. Several economies in the region, notably those of Greece, Spain, Portugal, and Ireland, are currently carrying very high debt levels. In Greece, for instance, the high current account deficit, which surpassed 12 percent of total GDP and triggered a debt crisis, led the country nearly to default. However, a rescue package assembled jointly by the European Union, the International Monetary Fund, and the European Central Bank was implemented in May 2010 to prevent default and stop the crisis from spreading to other economies of the European Union. Greece accounts for less than 3 percent of the European Union's total GDP, but signs of structural problems in the economies of Spain, Portugal, Ireland, and to a lesser extent Italy may weigh heavily on the economic recovery of OECD Europe as a whole. In the *IEO2010* Reference case, total GDP in OECD Europe does not recover to its 2007 level until 2012. Economic growth in the region averages 1.7 percent per year from 2007 to 2035, below the increase of 2.0 percent per year for the OECD as a whole.

Japan was among the OECD economies hardest hit by the global economic downturn. Beginning in the second quarter of 2008, its GDP declined in four consecutive quarters. The International Monetary Fund estimates that, on an annualized basis, Japan's GDP contracted by more than 10 percent per year in the fourth quarter of 2008 and the first quarter of 2009. Although the Japanese banking sector was relatively insulated from the global financial crisis that began in 2007 and worsened in 2008, demand for Japanese goods declined precipitously as some of Japan's largest customers fell into recession. In the past, Japan has relied on exports to generate about one-third of its GDP growth, and the decrease in exports strongly affected its economy.

Although improving exports and government incentive programs (which have stimulated domestic consumer demand) should allow Japan's GDP growth rate to improve in 2010, the pace of recovery is likely to be tied to those of its major customers in the United States and OECD Europe. In the long term, Japan's aging labor force and declining population are likely to result in substantially slower economic growth over the projection period, averaging 1.4 percent per year from 2009 to 2020 and 0.3 percent per year from 2020 to 2035.

More robust economic growth occurs in the rest of OECD Asia. In South Korea, GDP growth averages 2.9 percent per year from 2007 to 2035. The global recession led to profound declines in Korea's exports and domestic demand in 2008 and into 2009. In response to the deepening economic crisis, the Bank of Korea cut its interest rate six times between October 2008 and February 2009, to 2.0 percent, where it remained into 2010. In addition, the South Korean government introduced stimulus packages worth about $44 billion (50 trillion won) into the economy to stimulate domestic demand. South Korea's economy began to recover in the second half of 2009, recording double-digit growth rates in the second and third quarters, as exports to China increased sharply and the effects of the stimulus funds were felt. A return to world demand for Korean goods will support the South Korean economic recovery in the near term. In the long term, however, its growth tapers off as the growth of its labor force slows.

GDP growth in Australia/New Zealand averages 2.6 percent per year from 2007 to 2035 in the IEO2010 Review case. To address GDP growth that slowed markedly in Australia and declined in New Zealand as a result of the global recession, the Reserve Bank of Australia and the Reserve Bank of New Zealand eased monetary cushion the impact of the global economic downturn. Australia's recovery is already well underway, with GDP growth expected to return to pre-crisis trend levels of about 3.0 percent per year in 2010. In fact, Australia was the first "Group of 20" nation to begin tightening monetary policy and increasing interest rates in October 2009. Interest rates have increased periodically since that time, reaching 4.0 percent in 2010. In comparison with Australia, New Zealand's economic recovery has been tepid, and interest rates remained at record low levels of 2.5 percent through the first quarter of 2010 with assurances that monetary policy would begin to be tightened by mid-year. Long-term prospects in both countries are relatively healthy, given their consistent track records of fiscal prudence and structural reforms aimed at maintaining competitive product markets and flexible labor markets.

3.4.2 Non-OECD economies

Overall non-OECD economic growth averages 4.4 percent per year in the *IEO2010* Reference case from 2007 to 2035. Economic growth in non-OECD Europe and Eurasia as a whole averages 2.7 percent per year. After several years of strong regional economic growth (the region's GDP grew by an average of 6.7 percent per year from 2000 to 2008), GDP in non-OECD Europe and Eurasia contracted by 7.3 percent in 2009. The region has a fairly diverse set of economies, and while some suffered deep recessions in 2008-2009, others saw economic growth slow but remain positive.

Those nations reliant on commodity exports tended to fare worse than their neighbors in the recent recession. For example, in Russia - the region's largest economy - GDP declined by 8.0 percent in 2009; Ukraine's GDP declined by 15.0 percent; and Kazakhstan's GDP declined by a more modest 1.1 percent. In contrast to the sharp economic declines among the energy-exporting nations of non-OECD Europe and Eurasia, other smaller regional economies with strong domestic demand were affected only slightly by the global economic downturn. For instance, both Albania and Uzbekistan recorded GDP growth of more than 4 percent in 2009. Beginning in late 2007, it became more difficult for banks and other entities in non-OECD Europe and Eurasia - particularly, Russia, Kazakhstan, and Ukraine - to gain access to foreign loans. The impact was softened somewhat by higher world market prices for commodity exports, but with the subsequent collapse of commodity prices and worsening global economic situation, the region's economic growth declined sharply. In the mid- to long term, a return to high world oil prices stimulates investment outlays, especially in the energy sector of the Caspian region. Given the volatility of energy market prices, however, it is unlikely that the economies of non-OECD Europe and Eurasia will be able to sustain their recent growth rates until they have achieved more broad-based diversification from energy production and exports.

Much of the growth in world economic activity between 2007 and 2035 occurs among the nations of non-OECD Asia, where regional GDP growth averages 5.2 percent per year. China, non-OECD Asia's largest economy, continues playing a major role in both the supply and demand sides of the global economy. *IEO2010* projects an average annual growth rate of approximately 5.8 percent for China's economy from 2007 to 2035 - the highest among all the world's economies. Non-OECD Asia is leading the recovery from the 2008-2009 global economic recession. The substantial Chinese stimulus, considerable loosening of lending terms, and tax breaks for new cars and appliances have translated to a 17-percent increase in retail sales (the largest increase in more than 20 years) and an 18-percent increase in industrial production. It now appears that China posted a 9 % increase in GDP in 2009, and that it is on its way to returning to double-digit growth in 2010. One caveat is that the government is attempting to remove stimulus spending and tighten lending terms in order to eliminate incentives for over investment and to control price inflation in the short term. Many non-OECD Asian economies that are trade partners with China have also benefited from their ties with China. Although these emerging Asian economies - particularly those strongly dependent on exports for revenues - experienced profound decreases in economic activity in 2008 and into 2009 as demand for goods among OECD economies sharply declined, the recovery in China has bolstered their recovery.

Structural issues that have implications for economic growth in China in the mid to long term include the pace of reform affecting inefficient state-owned companies and a banking system that is carrying a significant amount of non performing loans. Development of domestic capital markets continues in the *IEO2010* Reference case, providing macroeconomic stability and ensuring that China's large domestic savings are used more efficiently.

India's economy is not as dependent on export revenues as are the economies of China and some of the other non-OECD Asian countries. About 75 percent of India's population still depends on farming for income. As a result, India was affected far less by the global economic downturn than were many other nations of the world. India's GDP grew by about 6.0 percent in 2008 and 2009 and is expected to grow by 7.5 percent in 2010.

Its GDP growth is expected to return to pre-recession trends over the next year or so, with positive prospects for the economy in the mid-term, as it continues to privatize state enterprises and increasingly adopts free market policies. Accelerating structural reforms including ending regulatory impediments to the consolidation of labor-intensive industries, labor market and bankruptcy reforms, and agricultural and trade liberalization remain essential for stimulating potential growth and reducing poverty in India over the mid to long term. In the *IEO2010* Reference case, GDP growth in India averages 5.0 percent per year from 2007 to 2035. Outside China and India, recovery from the global recession in the countries of non-OECD Asia is likely to vary. Those economies that are export-dependent (including Hong Kong, Indonesia, Singapore, and Taiwan) weakened substantially in 2009, as demand in the United States, Europe, and Asia declined and industrial production contracted by about 25 percent. For the export-dependent nations, China's strong economic rebound is likely to support recovery in the near term.

For nations where domestic demand remains healthy (including Vietnam and the Philippines), the impact of the global recession was less severe, although their growth did slow in 2009. Overall, long-term economic activity in the nations of non-OECD Asia remains robust. From 2007 to 2035, national economic growth rates for the region excluding China and India average 4.3 percent per year, as labour force growth rates decline and economies mature.

From 2003 to 2008, rising oil production and prices helped boost economic growth in the oil-exporting countries of the Middle East, many of which also benefited from spillover effects on trade, tourism, and financial flows from the region's oil exports. The sharp decline in world oil prices at the end of 2008 and into 2009, combined with OPEC-imposed production cuts, declining demand for other exports, and reduced capital inflows, slowed economic growth to its lowest rate since 1994. Stimulus funding from Saudi Arabia, the United Arab Emirates, and other countries in the region helped to keep GDP from falling lower. With strengthening oil prices and rebounding demand for the region's export commodities, prospects for economic growth remain favorable. The Middle East's reliance on oil and natural gas revenues continues for much of the projection period.

The impact of the global recession on the economies of Africa varied across the continent. In the countries of Southern Africa, GDP declined by 1.9 percent in 2009. South Africa, the region's largest economy, experienced its first recession since 1992, and the impact spread to neighboring countries. Western Africa's economic growth slowed but remained positive, as Nigeria, the second largest economy in sub-Saharan Africa after South Africa, saw increases in agricultural output that offset declines in industrial output and oil production. Northern African nations benefited from strong domestic demand and high agricultural output from Algeria and Morocco. Eastern African nations experienced robust economic growth in 2009, largely because of strong economic performance in Ethiopia and the member countries of the East African Community (Kenya, Uganda, Rwanda, Burundi, and Tanzania).

In the *IEO2010* Reference case, Africa's combined economy grows at an average annual rate of 3.6 percent from 2007 to 2035, supported by the expansion of exports and robust domestic demand in many of the continent's national economies. Nevertheless, both economic and political factors, such as low savings and investment rates, lack of strong economic and political institutions, limited quantity and quality of infrastructure and human capital, negative perceptions on the part of international investors, protracted civil unrest and political disturbances, and the impact of disease present formidable obstacles to growth in a number of African countries.

As in Africa, the impact of the global economic downturn on the nations of Central and South America varied across the region. Brazil, the region's largest economy, is already well along the path of recovery after experiencing a relatively short and mild recession in 2009. Its recovery is supported by domestic and foreign investment, along with strengthening domestic consumption. Other countries including Argentina, Bolivia, Ecuador, and Venezuela are expected to recover much more slowly.

Investment in the countries of Central and South America is constrained by adverse economic circumstances, and revenues from commodities exports are not expected to provide the level of government revenue that they had from 2003 to 2008. The proximity of the region to the United States and the trade relationships of its national economies with the U.S. economy suggest that the region's recovery will be linked, in part, to the pace of the U.S. recovery. Even so, the long-term prospects for Central and South America remain positive.

Most countries in the region have flexible exchange rates, positive trade balances, and relatively low fiscal deficits and public debts. Regional inflation is lower than it was in the mid-1990s, and a relatively young labor force supports the region's economic growth prospects over the next 30 years. Economic growth in Central and South America averages 3.4 percent per year from 2007 to 2035 in the Reference case, as the region benefits from the expected recovery in world economic growth after 2010, and foreign capital flows are revived.

3.5 Sensitivity analyses - Alternative Economic Growth cases

Expectations for the future rates of economic growth are a major source of uncertainty in the *IEO2010* projections. To illustrate the uncertainties associated with economic growth trends, *IEO2010* includes a High Economic Growth case and a Low Economic Growth case in addition to the Reference case.

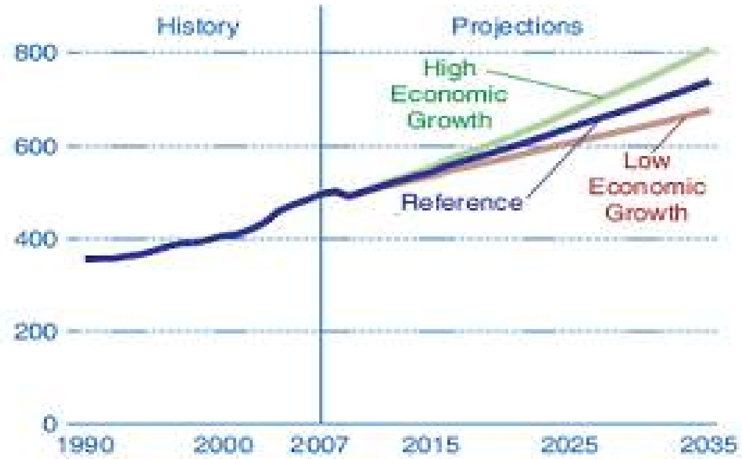
The two alternative growth cases use different assumptions about future economic growth paths, while maintaining the same relationships between changes in GDP and changes in energy consumption that are used in the Reference case. The alternative growth cases maintain the oil price path of the *IEO2010* Reference case.

In the High Economic Growth case, 0.5 percentage point is added to the annual growth rate assumed for each country or country grouping in the Reference case. In the Low Economic Growth case, 0.5 percentage point is subtracted from the Reference case annual growth rates.

The *IEO2010 review* shows total world energy consumption reaching 739 quadrillion Btu in 2035 - 281 quadrillion Btu in OECD countries and 458 quadrillion Btu in non-OECD countries. In the High Growth case, world energy use in 2035 totals 810 quadrillion Btu, 71 quadrillion Btu (about 35 million barrels oil equivalent per day) higher than in the Reference case. In the Low Growth case, total world energy use in 2035 is 60 quadrillion Btu (30 million barrels oil equivalent per day) lower than in the Reference case. Thus, the projections for 2035 in the High and Low Economic Growth cases span a range of uncertainty equal to 134 quadrillion Btu (Figure 3.11).

Figure No. 3.11

World marketed energy consumption in three economic Growth cases, 1990-2035 (quadrillion Btu)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

Figure No. 3.12

World Oil price - in three different cases 1990-2035 (dollars per barrel)

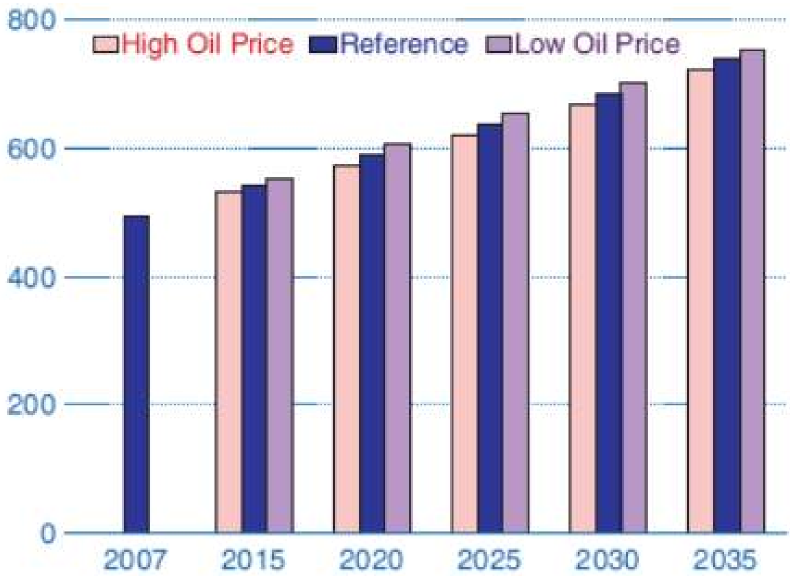
Source: U.S. Energy Information Administration / International Energy Outlook 2010

3.5.1 Alternative Oil Price cases

Assumptions about world oil prices are another important factor that underscores the considerable uncertainty in long-term energy market projections. The effects of different assumptions about future oil prices are illustrated in *IEO2010* by two alternative oil price cases. In the High Oil Price case, world oil prices (in real 2008 dollars) climb from $59 per barrel in 2009 to $210 per barrel in 2035; in the Low Oil Price case, they decline to $52 per barrel in 2015 and remain approximately at that real level through 2035. In comparison, world oil prices rise to $133 per barrel in 2035 in the Reference case (Figure 3.12).

Figure No. 3.13

World marketed energy consumption in three oil price cases, 2007-2035 (quadrillion btu)

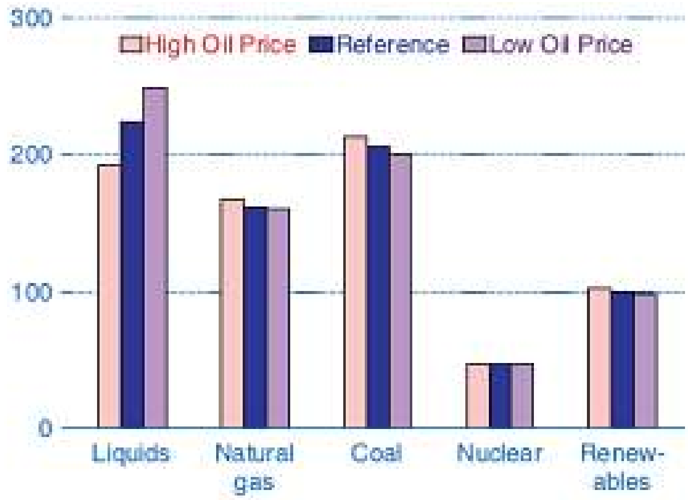


Source: U.S. Energy Information Administration / International Energy Outlook 2010

Although the difference in world oil prices between the High and Low Oil Price cases is considerable, the projections for total world energy consumption in 2035 do not vary substantially among the cases. The projections for total world energy use in 2035 in the High and Low Oil Price cases are separated by 33 quadrillion Btu (Figure 3.13), as compared with the difference of 134 quadrillion Btu between the High and Low Economic Growth cases. The most substantial impacts of the high and low oil price assumptions are on the mix of energy fuels consumed in each region—particularly, fossil fuels (Figure 3.14).

Figure 3.14

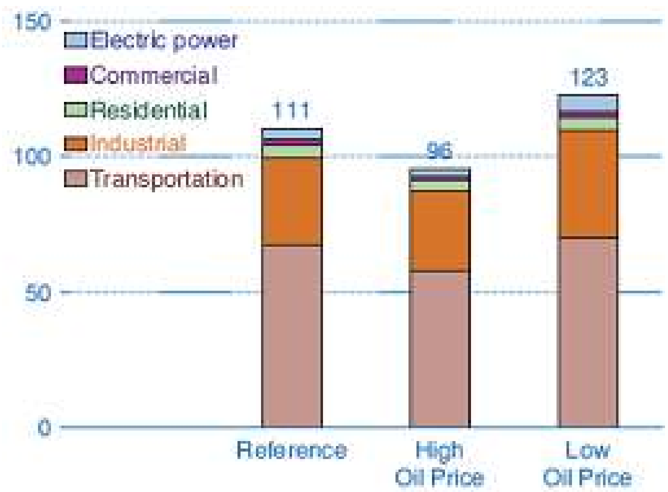
World marketed energy consumption by fuel in three oil price cases, 2035 (quadrillion Btu)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

Figure 3.15

World liquids consumption by sector in three oil price cases, 2035 (million barrels per day)



Source: U.S. Energy Information Administration / International Energy Outlook 2010

In the High Oil Price case, total world liquids consumption in 2030 is about 31 quadrillion Btu lower (about 15 million barrels per day oil equivalent), coal consumption in 2035 is 7 quadrillion Btu higher, natural gas consumption is 5 quadrillion Btu higher, and renewable energy use is 2 quadrillion Btu higher than projected in the Reference case. The difference in nuclear power consumption between the two cases is small. In the *IEO2010* Reference case, world oil prices begin to rise after 2009 and reach $133 per barrel by 2035. As a result, liquids consumption is curtailed in countries that have other fuel options available, especially in the electric power sector, where coal and other fuels can be substituted. Worldwide use of liquids for electricity generation, which falls by 1.5 quadrillion Btu from 2007 to 2035 in the Reference case, increases by 1.7 quadrillion Btu in the Low Oil Price case, as non-OECD countries retain their oil-fired generating capacity in the lower price environment.

In the Low Oil Price case, consumers increase their use of liquids for transportation, and there is less incentive for movement away from liquids to other energy sources in sectors where fuel substitution is fairly easy to achieve (for example, electricity). Total liquids consumption in 2035 is 25 quadrillion Btu (12 million barrels per day) higher in the Low Oil Price case than in the Reference case, reflecting increased demand in all the end-use sectors. In the Low Oil Price case, the industrial sector shows the largest increase in liquids consumption (14 quadrillion Btu or 7 million barrels per day) in 2035 relative to the Reference case (Figure 26), followed by the transportation sector (7 quadrillion Btu or 3 million barrels per day) and the electric power sector (3 quadrillion Btu or 2 million barrels per day).

CHAPTER – 4

COST STRUCTURE OF POWER SECTOR

4.1 Introduction

The various components, which constitute power tariff, are deliberated in this chapter. The cost of a power project is recovered over a long period of time say 10 to 35 years by selling electricity generated from the project or power plant. The capital cost of power plant, transmission and distribution lines, substations and other infrastructural facilities and cost of operation and maintenance etc will have to be recovered from selling energy over a period of time.

Since capital investment decisions are irreversible in nature, various economic and financial aspects of the new projects need to be evaluated before taking a final decision to go ahead with implementation of projects. Various financial tools or models used are payback period, accounting rate of returns, net present value, internal rate of return, cost-benefit analysis etc. The plant load factor and economics aspects of generation, transmission and distribution charges including losses, operation and maintenance costs, depreciation, return on equity, interest on loan etc also to be considered.

The project cost is recovered over a long period to smooth out the tariff impact arising out of lumpy additions of infrastructure, and also to match the tariff payments with the repayment of investment, which is done over the life of the asset. The costs associated with capital expenditure can be broadly classified as fixed and variable costs. Since most of the capital investments are materialized through a combination of loan and equity, loan repayment and profit on equity are legitimate costs associated with the investment.

4.2 Fixed Cost

Fixed costs recovered from consumers can be organized under the following five major heads.

4.2.1 O&M Costs

Operating and Maintenance costs cover the cost of repairs of transmission and distribution lines, meters, transformers or power stations. The routine operation and essential maintenance expenses are charged to this head. The salaries directly attributed to these functions and the cost of jobs contracted out can also form part of it. The cost of insurance against accidents, natural calamity etc payable in the form of annual installments is included under O&M head or shown under a separate head. All these costs are recovered from consumers through tariff in the same year.

4.2.2 Return (Profit) on Equity:

It is legitimate for the project owner to seek a profit on his equity. For the most private projects in the past, the allowed profit varied between 12 to 30 % of the equity amount. This is directly recovered from the consumers through the tariff. This charge remains till the project remains in operation. The recent regulatory orders indicate a base return on equity around 12-14 %. But actual profitability can vary depending upon the performance linked incentives / disincentives.

4.2.3 Income Tax

The income tax of the utility on the base return (profit excluding incentive) is a pass through – implying that it is recovered through tariff. Hence the consumers pays not just utility profits but also tax on the profit.

4.2.4 Interest on Loan

The project owner has to pay the interest on loan taken to construct the project. The interest burden goes on reducing as the principal amount of loan is repaid and finally vanishes along with the loan. Interest payment expenses are also directly recovered from the consumers in the same year. Therefore, for consumers it is important that the power project gets a low interest loan so that this charge is low.

4.2.5 Repayment of Loan / depreciation

Loan repayment is a cost to the project and is paid through tariff. However, accounting norms do not allow this to be charged directly to the tariff, but use a concept called depreciation. Depreciation measures the reduction of value of an asset due to aging and use. Towards the end of the life of an asset, the asset value drops to a negligible amount. Depreciation is recovered through the life of the equipment, and hence the longer the life, the less the depreciation per year. Therefore, the rate depreciation is different for different equipment or assets. Depreciation is calculated as a percentage of cost of assets and this percentage is called ‘allowed rate of depreciation’.

The repayment period of loans availed by private sector projects is shorter (8 to 10 years) compared to that of government loans availed by SEBs (15 to 20 years). Therefore, in case of private companies producing power (IPPS), the old rate of depreciation was not sufficient enough to repay the loans and in such cases the promoter had to repay the loan from its profit resulting in reduction of profit during the initial years. This was not acceptable to private investors and hence the Government of India permitted IPPs to claim additional depreciation in advance to match the loan repayment schedule. This increase in depreciation rate has resulted in higher tariffs for a decade or so, i.e. till the loan repayment is complete. This was seen by public sector as a discrimination against them and subsequently the Government also increased the depreciation rate applicable to public sector.

Due to depreciation, the value of machinery or assets is getting reduced in the account books. This reduced value is called ‘book value’ of an asset (also known as net fixed assets). After some years, the assets become worthless in the account books, but have a lot of useful life left out and have substantial market value. This happens especially for land or hydro plants, which have more life than what is considered by accounting rules.

In Orissa, the electricity tariff increased due to asset revaluation, which is not. As the book value of an asset can be much lower than its usefulness or market value (i.e. ability of assets to generate future income) revaluation of assets, which is paper magic, can be done to increase the value of assets to reflect market value. The increased value of assets was shown as coming from the government in the form of increase in equity. This window dressing was done because the cost of assets was low compared to the loan the SEB had, and it would not be considered as a viable enterprise. The evaluation increased the cost of assets to balance the loan.

This paper transaction increased the cost of assets, leading to a higher amount being charged as depreciation and higher profit being demanded corresponding to increase in equity. Both these factors increased the tariff. In simple terms, the magic by the economists and accountants painted a rosy picture, while increasing future tariffs for consumers. However, the regulatory commission later addressed this problem by treating some of the increased costs as ‘regulatory assets’, which are not recovered immediately but maintained on the utility’s balance sheet to be recovered in the future. After the Orissa experience, other reforming states have avoided such revaluation of assets.

4.2.6 Cost of Working Capital

The last and relatively small component of fixed cost is to cover the cost of obtaining working capital. The spares or the stored fuel are funded through working capital. The owner of the project can charge interest on the working capital in the tariff.

4.3 Variable cost

Variable cost is a significant cost for fuel based (coal, naphtha, furnace oil, diesel, LNG, CNG etc) power projects. Fuel cost is dependent on the unit price of the fuel, specific fuel consumption, actual generation of the plant or PLF (Plant Load Factor). Hence, this cost is a variable cost. In some situations, part of O&M cost is also linked to usage of plant or equipment. This is can also form part of variable cost.

On the other hand, in some situations even the fuel cost ends up becoming a fixed cost. This happens if the fuel is purchased through contracts that have a 'take-or-pay' clause. Some of the earlier LNG contracts had such terms. In such cases, some minimum guaranteed fuel purchase was mandated, which was equal to the fuel requirement of the plant at, say, 60-70 % PLF. Consequently, irrespective of whether one runs the plant to that extent, the minimum fuel cost has to be paid. Therefore, this part of fuel cost no more remains a variable cost but becomes a fixed cost. The minimum plant usage gets fixed as per the fuel contract or the PPA and the plant is called a 'must run' plant. Such plants have to be kept out of the load-dispatch logic that gives priority to the lowest variable cost plants.

The fixed and variable costs have to be recovered from consumers through tariff. All costs are clubbed and divided by the useful output to arrive at the tariff of that project.

4.4 Moves towards normative or benchmark values

The National Tariff Policy – 2006 as per Electricity Act 2003 clearly moves away from project-by-project approvals. Now the regulator is allowed to use normative values for loan term and interest rates. The CERC has already set the norms for fuel consumption (heat rate) and O&M costs as function of size of the plant, technology and plant vintage. If the project owner can avail a cheaper loan or long-term loan, or can improve the heat rate below the benchmark rate, he makes the profit, which is acceptable in law. On the other hand, the plants exceeding the norm cannot pass on this high cost to consumers.

4.5 Hidden costs – the externalities

Other than conventional cost as appearing in the account books, there are several other costs that are paid by people, which seldom appear on paper. These costs are never internalized by power sector and hence are called externalities.

Electricity is a non-polluting form of energy at the point of use, but at the point of generation, the social and environmental impacts of the power sector are very serious. Coal projects are responsible for carbon dioxide emission, which contributes to global warming. Increasing global temperatures are likely to cause massive and unpredictable changes in the global weather and increase in coastal flooding. Coal burning creates ash as a by-product, which is cause of heavy metal pollution. Sulphur dioxide and nitrogen oxide emissions induce acid rain, which causes water pollution and reduces crop yield. Historically, it has remained hard to quantify the cost associated with emissions. Hydroelectric or nuclear plants produce no emissions but these sources have their own serious problems.

Dams and mines uproot thousands of people, disrupt local environment and disturb the water balance in surrounding areas. All these costs are actually paid by someone, either as reduced fish catch in the river or people being uprooted or deprived of their natural habitats. If we fail to take care of the externalities of hidden costs, we would be stepping on the toes of the poor and disadvantaged and neglecting the future of next generations. Hence it is imperative to take these costs seriously. Some steps to reduce these costs are:

- Environment and social impact assessment to be conducted with serious intent, and results inclusive mitigation plans to be made public.
- Proper project siting can substantially reduce the impact of pollution and other harmful social impacts.
- Rehabilitation and settlement of displaced people needs to be ensured before the project goes ahead. Moreover, energy conservation, efficiency improvement and promoting development of renewable energy projects needs to given due focus.

4.6 Generation tariff

Generation tariff constitutes about half of the cost paid by the consumer. It is usually described as cost of unit of service. Service could be energy supplied in units (kWh) and maximum power demand (MW).

4.6.1 Single part versus two-part tariff

The simplest form of tariff is the single part tariff, which is worked out by dividing all approved costs (fixed + variable costs) by the net generation. The net generation is equal to the gross generation minus the auxiliary consumption of the plant. NTPC followed this tariff plan till some years ago with State Electricity Boards (SEBs) as captive customers. But the singe part tariff resulted in lot of problems as SEBs were unwilling to purchase power during night as they had sufficient generation at that time and low requirement during off-peak hours (10 pm to 6 am). The NTPC did not reduce power generation at night, resulting in excess generation, high frequency and even grid instability at night. These problems were resolved by converting NTPC tariff from single part tariff to two-part tariff. In two-part tariff, the fixed cost is linked to plant availability and the right of the customer to use capacity of the plant. The monthly fixed cost is divided by plant capacity to arrive at this fixed charge (Rs./MW/month). This is like a rent. The variable cost charged on the energy sold. Therefore, the monthly cost has two parts, one derived from Rs./MW per month, and the second derived from variable cost of Rs./Unit (kWh)

4.6.2 Two part, cost plus tariff for IPPs

During the mid 1990s, SEBs and state governments secretly negotiated IPP projects without competitive bidding or transparency. After signing the initial contract, the IPP needed the CEA to approve the capital cost, debt equity ratio and details of the loan package (interest and term of loan). But the CEA scrutiny was liberal and in some cases CEA was also under pressure from the ministry to give approval irrespective of its views. As a result, the CEA overview did not always work.

Some of the infamous IPPs in India include: Dabhol Power Company (DPC) in Maharashtra promoted by Enron, Cogentrix in Karnataka, and Spectrum in AP.

Almost all IPP contracts in India have a two-part tariff. As integrated utilities are now being unbundled, even the public sector generation plants are employing two-part, cost plus tariff. For simplicity and ease of understanding, let us continue with the example of IPP. If the IPP ensures that plant availability is maintained above the agreed level, the· fixed cost has to be paid irrespective of dispatch (PLF). The components of fixed cost, i.e. O&M cost, insurance cost, interest on working capital, return on equity (RoE) etc were agreed in the power purchase contract, with a ceiling set by the Ministry of Power. An incentive in the form of increase in RoE is given if plant availability or PLF is above the normative level. The Ministry of Power announced a ceiling rate for different charges, maximum allowed incentive, and the fuel consumption norm (heat rate – means heat in kilocalories required to produce one unit of power from a thermal power plant which in turn depends on the overall thermal efficiency of power plant). These ceiling norms were criticised as being too liberal and were later made somewhat more stringent. The MoP norms for IPPs differed with the type of generating plant. For example, the ceiling for O&M cost was 2.5% of capital cost for coal projects and 1.5 % for hydro projects. Initially an RoE of 16% was allowed for normative plant availability. Normative availability was initially pegged at 68.5%. For availability greater than the normative level, each percentage point of higher availability was awarded an incentive of 0.7% increase in the RoE. So 95% availability would imply a RoE of 34.6 (=16 + (95-68.5) x 0.7). This was excessive profitability, especially as the RoE was given in the same currency as the equity (so an investment in US $ would get 34.6% RoE in US $). The tax on profit was considered as a pass-through in tariff and hence this was post tax profit. To reduce the profitability, CEA raised the normative availability level for coal and CCGT plants and allowed incentive only if the plant was actually dispatched. The tax exemption and the foreign exchange protection were restricted to only the first 16 % of the assured return and not on the incentive.

As the process was not fully rational, many inconsistencies and deficiencies remain. For example, to get high incentive, some IPPs demanded (and SEBs/State governments accepted) that the IPP plant would be the last to be backed down, irrespective of its variable cost. Such provisions ensured that IPPs got higher dispatch of power quantity and hence higher profits. This harmed the public interest much more than the higher profit given to IPPs, as it went against merit order principle (Merit order principle means shutting down or backing down costly generating stations, in the order of variable cost (or fuel cost) of generation per unit (kWh) during periods of low energy demand. When there is low demand, only low cost generating stations need to be operated to bring down average cost of energy per unit). In some other cases, IPP plants were run at near full load even when the system was over producing (with frequency higher than 50 Hz). This must have been done to achieve higher PLF of these plants in order to reduce their tariff (in Rs./Unit).

4.6.3 Availability Based Tariff (ABT)

Almost all Indian States including Kerala entered into ABT regime from 1 January 2003 onwards. ABT is a three-part tariff system implemented throughout the country (except in one region in north) with the following specific intentions:

1. To make an integrated national grid by maintaining uniform frequency throughout the regional grids and minimising variations in operational parameters of the grid for achieving grid discipline. The target frequency prescribed by Indian electricity rules is 50 Hz.

2. Normalisation of grid frequency necessitates proactive load management by beneficiaries (state Electricity Boards and other supply utilities) and dispatch discipline by Generating companies.

3. Financial incentives to promote grid discipline – Those who overdraw power (compared to their scheduled power demand declared on the previous day – this over-drawing/under-drawing is called Unscheduled Interchange (or UI)), at lower frequencies will be penalized by imposing a high tariff rate and those who draw more power at higher frequencies need pay less or nil tariff rate. The tariff rate for Unscheduled Interchange in the drawing of power varies from Rs. 0 (zero) to Rs. 6 (subject to periodic revision by CERC), which is inversely with system frequency prevailing at the time of supply/consumption. In a similar way, generating companies, which make variations in the scheduled supply of power, will be penalized or given incentives. In short, it is system of rewards and penalties seeking to enforce day ahead pre-committed schedules, to maintain grid discipline, though variations are permitted if notified 1 ½ hours in advance.

4. ABT facilitates 'merit order backing down' of generating stations during low demand or off peak period. That is, generating stations with high unit cost of power would be shutting down first followed by other stations on the basis of unit cost of generation. Considering Kerala State's comparatively superior position in the generation of low cost hydel power, which can be easily regulated unlike thermal power stations, state can harness the advantage of ABT tariff by maximising consumption during off peak hour. In other words, during off peak hours, if frequency is high, KSEB can draw power at very low rate / unit (UI rate) and reduce hydel generation to preserve water in dams so that generation of low cost hydel power can be maximised during peak hours. If meticulously planned and implemented, KSEB can avail the double benefit of drawing low cost power from central grid during off-peak hours (frequency is high and rate is very low) and reduce the import of costly power during peak hours (when frequency is low and rate is high) by maximising own generation.

The three-part tariff consists of:

Part (a): A **fixed charge** payable every month by the beneficiary (SEBs or other utilities) to the generating company for making capacity available for use. This varies with the share of a beneficiary in a generators capacity and also with the level of availability of achieved by a generator.

Part (b):An energy charge per unit of energy supplied on the basis of **variable cost** and as per the **pre-committed schedule of supply** from the generating station, drawn up on daily basis.

Part (c):A charge for **Unscheduled Interchange** in supply and consumption of energy in variation from the pre-committed daily schedule. This charge varies inversely with **system frequency** prevailing at the time of supply/consumption.

ABT Tariff = Part (a) + Part (b) + Part (c)

ABT was first introduced on 1 January 2003 to enforce frequency discipline among various transmission regions as well as among the states coming under a particular region. For example Kerala, Tamil Nadu, Karnataka, Andhra Pradesh, Goa and Pondicherry are the states coming under southern regional grid. SRLDC (Southern Regional Load Dispatch Centre) is the nodal agency administering ABT in Southern Region. At present states are moving towards intra-state ABT regime, which is similar to the ABT scheme mentioned above. In other words, intra-state ABT is a techno-economic tool similar inter-state ABT for bringing rational tariff structure for supply of electricity from state generators to the distribution licensees with the sole purpose enforcing discipline in the state grid, which in turn would benefit the region in which the state belongs.

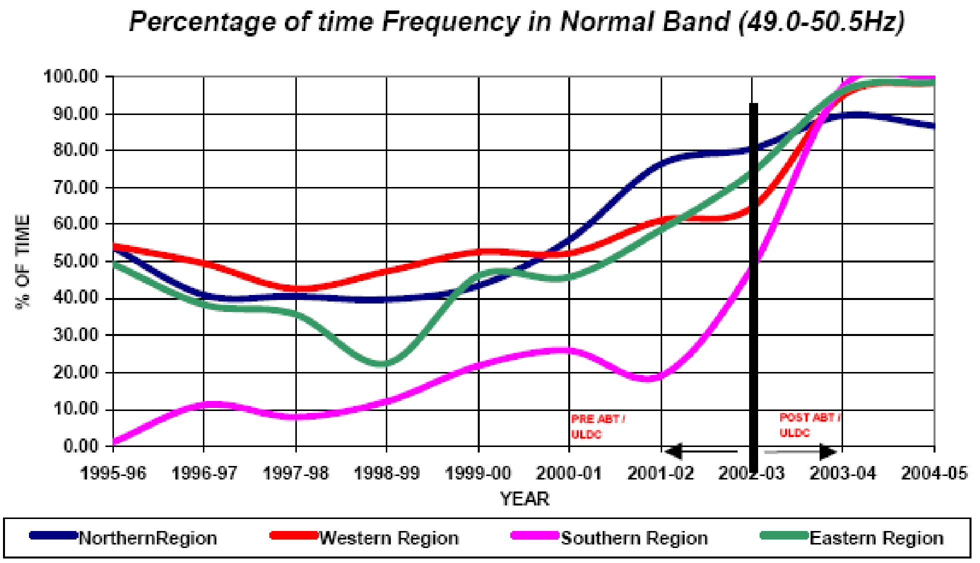
Figure No. 4.1

DERC-Unscheduled Interchange (UI) rates as on 31/03/2007

Source: Intra-state ABT order of Delhi Electricity Regulatory Commission (DERC) dated 31/03/2007

Figure No. 4.2

ABT Impact – Improvement in frequency fluctuations



Source: Planning Commission of India- Draft report on integrated energy policy 2005

Availability Based Tariff (ABT) and unscheduled interchange of power introduced in 2003 for inter-state exchange of power have reduced voltage and frequency fluctuations. They are still, however, not as stable as one would like. Figure 4.2 shows improvement in frequency fluctuation. Excepting for the Northern region frequency was within normal band for more than 98 percent of the time in 2004-05. The UI charges as decided by DERC on the basis of CERC guidelines is shown in figure 4.1

4.6.4 Risk sharing

In most IPP contracts, SEBs took all the risks apart from the plant construction and performance risk. These risks include the fuel cost variation, currency variation (as the loan and equity return were protected against currency variation), and possibility of lower demand etc. The promoters passed on the plant construction and performance risk to the equipment suppliers through construction contracts, the increased cost for which was built into the PPA. So, the promoters took effectively no risk. In fact, the only risk the promoters took was the risk of SEBs paying their bills!. But the high cost of IPP generation added to this risk and many SEBs started having problems in making timely payment to IPP projects.

4.6.5 Incentive to increase capital cost

The promoter had all the incentive to inflate the capital cost of the project. This would increase the tariff and actually the promoter would not put in the equity that is seen on paper. Through accounting jugglery, the promoter could claim that he had put in the agreed equity amount. A 10% increase in capital cost could allow the promoter to save nearly a third of his equity (assuming equity is 30% of project cost) whereas on paper his equity and profit would remain unchanged. Actually, the profit on real equity put in would increase substantially.

Let us understand this with the help of an example. The international norm for Capital cost of CCGT plants is about 600 $/kW. But an IPP gets approval for the capital cost of 800 $ /kW. He is expected to finance it by a combination of debt of $

560 and equity of $ 240 per kW. In reality, since his cost is only $600, he would put in the equity of $40 per kW. So the equity reduces substantially, but profit in dollar terms remains the same. Hence the profit as percentage of equity sharply increases.

The situation was worse for several projects in India. The costs of CCGT based IPP projects have been around 900 $/kW in India. In the case of Enron's Dabhol power project, the cost approved was 1,100 $/kW - nearly twice the norm. In such situations, one suspects that promoters are claiming that they have invested large amounts of money in building the project, when actually they have not invested any money but have constructed the project entirely with loans and, moreover, might have diverted part of the loan amount (for their own use).

In most cases, no stakeholder - Regulatory Commission, SEBs, or the government - has investigated the expenditure for the project. In a few cases where investigations have been done little action has been taken. In some cases, the high cost PPAs have been renegotiated or rescinded.

- In Gujarat and Tamil Nadu, the state government/SEBs renegotiated IPP contracts to lower the tariffs.
- MSEB rescinding the DPC contract was an attempt to reduce the damage. This led to a host of legal cases in Indian courts and in international arbitrations. Finally, in 2005, the NTPC and Gas Authority of India, along with MSEB took over the DPC from the foreign equity owners. The loan from foreign institutions was paid off. The fully Indian plant is now getting ready.

4.6.6 Competitive bidding – second generation IPPs

The misdeeds related to IPPs met with a lot of criticism following which, in February 1995, the Ministry of Power mandated competitive bidding for all new IPPs. The utility was to invite bids after announcing the type, location and size of the plant. Bidding was done on tariff for the energy generated. A pre-decided PPA was then signed with the lowest bidder. Only a few projects have been taken up through this route. These projects have clearly shown that cost could be substantially lowered through competitive bidding. But the risk-sharing pattern continued as earlier. The fuel price and demand risk continue to be taken by the utility. The recent development of allowing IPPs to directly sell to industry (open access) is one way of avoiding such risks. But, then, tariff is market driven, and if care is not taken it can be highly volatile.

A slightly modified form, called "all source bidding", can be used to remove one more disadvantage. The utility calls bids for generation of certain MW of power in a certain part of the state. The choice of fuel and the size of the plant are open to the bidders. Persons with existing captive plants can also supply excess power to the grid. Any person capable of supplying even part of the requirement at lower cost can compete. Cogeneration and small gas turbine plants (where piped gas is available) have been beneficiaries of this process in the USA and Europe.

4.6.7 Recent changes as per Electricity Act-2003

The Electricity Act has encouraged competitive bidding for all generation projects. The Ministry of Power has come out with guidelines for carrying out competitive bidding. Once the tariff of the project is determined through such competition, the regulatory commission has to accept that tariff. All private green-field projects have to be competitively bid. The government owned projects could be without competitively bidding for the next five years, where the regulatory commission is expected to oversee the reasonableness of capital cost. All the norms mentioned earlier, such as O&M cost, depreciation rate, heat rate (fuel consumption), terms of loan, and share of equity etc. are now decided by regulatory commissions. These norms are applicable only to the projects, which are based on capital cost approval - hence not applicable to projects decided through competitive bidding route. As mentioned previously, the regulatory commissions are moving toward normative values for all these factors, allowing inherent incentive to the project that can do better than these norms.

Hence, now for generation projects in the country, healthy and effective competition is critical in reducing the capital cost of power. As we have seen, the fuel cost constitutes a very large share of the generation cost. The Government of

India is in the process of setting up a system for determination of fuel prices, especially the coal prices that is based partly on regulation and partly on market forces.

4.6.8 Tariff for renewable energy projects

The world over, Renewable Energy power projects (RE projects) have been treated differently compared to conventional generation projects. They are given different incentives by several governments. RE projects are not seen as commercially viable by the utilities. This is partly due to the limited vision of the utilities and partly due to the emerging nature of the technologies. Different mechanisms have been evolved to encourage RE projects. These include (i) giving upfront subsidies including tax rebates. This is followed in India and the USA. (ii) Giving subsidy at the time of sale of power. The government pays a pre-decided subsidy per unit generation to the producer. This is followed in some parts of Europe. (iii) Forcing utilities to purchase a share of their power from RE projects, also called renewable energy portfolio standard. At times, a combination of these incentives is given. In India, the Ministry of Non-conventional Energy and the Ministry of Power decide these policies and subsidies.

There are cases of some RE projects finding undue favour with some state governments and getting excessive subsidies. The example of wind projects is worth mentioning. Initially, these projects received a large upfront subsidy without any control on quality or technology. As a result, the country saw several bad quality projects being put up while the promoter cashed the subsidy. Later, some state governments gave large sales tax exemptions linked to the capital cost of the project. This subsidy was higher than required when the preferential tariff was assured for the wind power. The subsidy (including tax concessions) over a period of six years has been nearly equal to the entire capital cost of the project. For example, wind projects in Maharashtra received tax breaks of nearly Rs. 2,000 crore for a capacity of 400 MW that produced electricity equivalent to a standard base-load plant of only 125MW. Moreover, as per the order of the regulatory commission, electricity from such highly subsidised projects is being purchased by the state utility (SEB) for a high cost of Rs. 3.25/unit. These subsidies could have been better utilised to support more wind projects. If the subsidy was utilised for energy conservation, then it would have saved much more electricity than is being produced by the windmills. The policies are now improving and projects that are technically better are also coming up.

The Electricity Act-2003 requires all state regulators to direct utilities to purchase a minimum of some percentage of power from renewable sources. Additionally, the National Tariff Policy requires the Central Regulatory Commission to set the tariff for electricity from the renewable energy sources that are not purchased through competitive bidding.

4.7 Transmission Tariff

Transmission tariff is similar to that of generation but is relatively simpler. The capital cost, transmission losses, and the availability of transmission lines are the three critical parameters for a transmission utility. The normative availability of transmission lines is 98% or more. The ERCs or government departments (in the absence of commissions) decide the norms for tariff and performance. The public sector transmission company POWERGRID has been responsible for strengthening and expanding the national grid. Intra-state lines were owned by the integrated SEB and there was no need to work out a separate tariff for these. In the restructured environment, where the state transmission company is separated, the construction of new lines is subjected to regulatory approval. The capital cost of such lines is recovered from all users of the network (irrespective of their actual use of the line). The long-term consumers of network, such as distribution utilities pay for the annual capacity charge of the entire network of the transmission utility. In other words, transmission is seen as a regulated activity. The regulatory commission is supposed to optimize the transmission planning and also take into consideration comments of all constituents or grid users. There is an exception of point-to-point (dedicated) transmission line, where the identified user pays for the full cost.

Regulator works out transmission tariff by dividing the approved cost (which consists mainly of the fixed costs) by the units transmitted by that line. It used to be worked out as Rs./Unit transmitted. Usually, the units sold to consumers are considered for tariff calculation, implying that the transmission losses are accepted without much scrutiny. Exceptions have been made as in the case of the AP Transmission Corporation, where the commission gave a target for reducing losses. If the Corporation is unable to reduce losses, it has to pay for the disallowed losses through its profits (and may even end up making losses). .

There is a move to allocate transmission charges not on units transmitted, but on the right to use the system. This is similar to the capacity charge for power plants (akin to rent). The consumers (typically SEBs) will have to pay these even if they do not use the transmission network, and can allow others to use the network. The tariff policy mandates CERC to evolve a system where the transmission charges would be a function of quantity of power transmitted, direction of flow, time, and distance of power flow. CERC is in the process of evolving such a tariff. The states would be then expected to follow similar tariff for intra-state transmission charges.

At times, customers of a transmission utility pay the power generator directly and pay only the transmission charges to the transmission utility. At other times, the payment for power purchase from the generator is made through the transmission utility. This is the case when TRANSCO (transmission company) is the single buyer and sells power to DISCOMs (distribution companies). In such cases, the transmission utility adds all its costs (including its power purchase cost) and bills it to its customers. In such cases, the Transco tariff is called Bulk Supply Tariff (BST). This can be just an energy charge (single-part tariff) but usually is a two-part tariff consisting of energy charge plus the demand charge (maximum demand met by Transco).

4.8 Distribution tariff

The economic issues in distribution are conceptually similar to that of transmission. However, the following features of the distribution business make the process of tariff determination complicated:

(a) Scattered points of sale

(b) Highly dispersed assets over a large geographical area

(c) Varied types of consumers with different consumption patterns and different commercial behaviour. (peaking versus nearly constant power requirement, Low Tension (LT) versus High tension (HT) supply etc.)

(d) Need for different performance parameters. For example distribution losses, recovery of bills (or revenue collection), line outages etc. Many of these parameters are difficult to monitor.

As we know, different tariff is applicable to different categories of consumers to reflect the cost to serve. However, by keeping the issues related to consumer tariff aside, an attempt made to understand the distribution costs and performance. The cost of distribution utility consists of the following:

(i) Power purchase

(ii) Transmission charges

(iii) Operating cost (O&M, depreciation, return on equity, interest on loan, depreciation etc.)

All these costs are examined by the regulatory commission and then allowed or disallowed. We have already discussed the first two cost components. Let us find out what constitutes the third component i.e. the operating costs of the distribution utility.

The O&M costs of distribution include the following:

(i) The salaries of staff for line maintenance, metering, billing, cash collection etc.

(ii) Cost of administrative offices, vehicles etc.

(iii) The cost of consumer grievance handling and fault reporting centres
(iv) Repair and maintenance of lines, substations and distribution transformers.
(v) Replacement of meters etc.

Since these costs are large, it is a practice to show the costs associated with establishment and administration separate from purely operation and maintenance cost. The establishment and administration cost includes cost of offices, office staff, vehicles, phone bills and cost of lawyers or legal proceedings. The O&M cost includes the cost of actual repairs, maintenance and the salaries of the staff directly involved in R&M. At times, even the material and manpower component of O&M cost is separately shown.

The assets of a distribution utility include the land, buildings and equipment of substations, Distribution Transformers (DTs), lines, meters etc. These assets are acquired by raising money in the form of a loan and/or equity. As in the case of generation and transmission assets, the cost of distribution assets - the interest on loan, depreciation, and the return on the equity - are recovered from the consumers as expenses.

The average tariff (for sale of electricity) is calculated by dividing the total allowed costs by the expected electricity sales. This is not a uniform tariff for all categories of consumers but an average of all consumers. The category-wise tariff setting has several different considerations as discussed in the next chapter.

At this point, let us briefly discuss the additional issues that need to be considered while deciding the average distribution tariff:

(i) Power distribution entails losses; these are technical as well as non-technical losses. Theft, malfunctioning of meters, un-read meters, and misplaced consumers ("meter-not found" category) are all included in non-technical losses. Hence, the average cost is worked out on the basis of likely sale of energy, taking into account such losses.

(ii) In Indian utilities, a large number of consumers are un-metered and their consumption is estimated. The losses are calculated using such estimated consumption. The method of arriving at this estimation has been a matter of dispute. Sample metering of such customers is becoming a more common method of such estimation. The National Tariff Policy expects the regulators to carry out Third Party measurements to verify such critical performance parameters of the utilities.

(iii) Even after billing, there are some consumers who may not pay their bill. And some amount of nonpayment, despite the best efforts of the company, is anticipated. This is referred to as 'bad debts' of the company and is usually in the range of 2 to 3% of revenue. This is not considered as income of the company. This is also called bill 'Collection efficiency'. Bad debts or arrears of the current and past years should be examined while determining tariff.

(iv) In the new environment, there has been an attempt to link both the factors - T&D losses and Collection efficiency - into a single parameter called AT&C (Aggregate Technical and Commercial) losses. This method was attempted to regulate the privatized distribution utilities in Delhi.

4.9 Financing of power sector investment

Financing of high investments in the power sector is a major worry for all power planners. Till the early 1990s, investments in the power sector were largely financed from government loans. The power sector was state owned and the government loans either came as budgetary support or as special purpose loans such as for rural electrification or for power plant renovation. The budgetary support came from the state and central government budget. But the power sector did not fully repay the budgetary support (loans), and some SEBs did not even pay the interest on these loans. The governments continued to give budgetary support even while having a deficit budget (expenditure exceeding income). By the early 1990s, India faced a foreign exchange crisis, and the state and central budgetary deficit had also increased substantially. An IMF loan was sought, which came with a condition: governments must reduce their budgetary deficit. The state utilities were not in a good financial situation - and no commercial lending agency would lend them money. As a result, the capital availability for the power sector reduced drastically.

To address this problem, the government decided to invite the private sector to build generation plants, which took the shape of IPPs. The SEBs were expected to get into long term contracts with these IPPs and the IPPs were to raise money from the market.

4.9.1 Financing of IPP projects

The promoters of IPP projects needed loans to fund the project (usually between 70 to 75% of the total investment). In most non-infrastructure projects, like a car factory, the owner takes a loan on the strength of the balance sheet of his other businesses. If the car factory cannot make a profit, the owner loses money; moreover the assets of his other businesses are at risk, as they are hypothecated against the loan for the car project. This mode of financing is called 'corporate finance'.

Infrastructure projects (including power projects) need very large capital, and few promoters are prepared to hypothecate (and risk) their ongoing business for these projects. Moreover, in India, the power utilities were the sole buyers for the IPP power - and were making large losses. Hence, the logic of the owner taking a business risk through such 'corporate finance' did not apply for power projects.

The promoters of IPPs insisted that the loan be given to the project, without hypothecating their balance sheet. This is called 'project finance'. Here, the security needed for lenders came from the power purchase agreement and the associated guarantees for payment. Hence, the lending agencies played a critical role in the project preparation period. They were expected to check if the project was really viable, equipment quality was good and the price was reasonable. They were expected to ensure that the project was profitable and, in turn, could ensure repayment of their loan. But in practice, most banks gave loans only on the strength of the guarantees associated with the PPA without a thorough scrutiny of the project. The banks did not even object to the high capital cost of IPP projects.

For many IPPs, a sizeable share of the loan came from the EXIM banks (Export promotion banks) of industrialised countries. Industrialised countries have these Export Promotion banks that give loans for different projects, provided the equipment required for the project is procured from that industrialised country. Funny as the world can be, these EXIM banks do not rely on PPAs, state government guarantees or even escrow accounts. Some EXIM banks demand that financing agencies in the borrowing country guarantee repayment of their loan (which was given to promote their exports) in the case of default. Some EXIM banks have sought guarantee from the Central government. In short, financing of IPP projects is a neatly woven web of guarantees given by different Indian entities on behalf of the Indian public.

Promoters of IPP projects typically put only half of the equity or less (implying less than 15% of the project cost, since equity is around 30% of total project cost). The promoter has full control of expenditure and project design, but has only a small stake (~15% of project cost). This becomes critical when there is a suspicion that the project cost is inflated. In such cases, the money actually invested (or risked) by the promoter may be negligible or nothing at all. As a result, consumers, government, or public owned financial agencies take nearly all the risks, while the promoter controls the expenditure.

4.10 Changing composition of SEB costs

The cost structure of utilities varies from utility to utility. It depends on the utility's historical cost and asset structure, and accounting practices. To get a broad idea of cost structure in India, let us see the accounting classification of the costs for 27 major public utilities (SEBs) in India. The SEBs are integrated utilities and hence costs of all segments are clubbed together and represented as paise per unit sold to consumers. The SEBs are being un-bundled into separate distribution, transmission and generation companies but this section will help us get a feel of the overall costs.

In accounting terms, these costs are shown under different headings, as shown in table 4.1. The costs do not include profit (or surplus) of SEBs. Since SEBs have been purchasing power from NTPC or IPPs in addition to their own generation; the cost of power purchase is seen separately from the cost of fuel burned in their own plants. Over the last decade, cost per unit sold has increased for the 27 SEBs at an alarming rate of 11% p.a. - a rate much higher than inflation. This is an important reason for electricity tariff becoming a hot issue. As can be seen from the table, the fastest growing costs have been (a) power purchase cost, (b) depreciation, and (c) establishment and administrative expenses.

Table No. 4.1

Cost of supply and its composition for public utilities

Item	**1990-91** (Paise /unit sold)	**2000-01** (Paise /unit sold)	**Increase** (%CAGR)
Fuel	26	50	6.8 %
O&M	5	10	7.2 %
Establishment/Admin	18	41	8.6 %
Misc. expenditure	5	5	0.0 %
Depreciation	6	20	12.8 %
Interest	20	39	6.9 %
Power purchase	28	139	17.4 %
Total (Paise / unit)	108	304	10.9 %

Source: Planning Commission – 2002: Annual Report on 'Working of State Electricity Board and Electricity Departments'

The SEBs were short of capital and did not build their own plants, but rather depended on central sector plants to meet the need for incremental demand. The depreciation has increased rapidly in the last decade because the depreciation rates were hiked in the last decade and the capital investments by SEBs were not well regulated. The fuel cost increase appears small (6.8 % p.a.) but if fuel cost was calculated as Rs./self-generation, the fuel cost increase would be much higher. The share of self-generation has been decreasing due to increasing power purchase. The fuel cost increase was high due to rapid increase in administered coal prices.

When electricity tariffs increase at a greater rate than the rate of inflation, it hinders the growth of the economy. Hence consumers need to understand and care about these issues.

CHAPTER-5

PROCESS AND PRINCIPLES OF REGULATORY REVIEW

5.1 Introduction:

Tariff is the rate at which electricity is sold to the consumers. It is the most common interface between the consumer and the utility. Tariff depends upon utility's costs, which in turn are dependent on the utility's planning and operational decisions. Tariff for the individual consumer depends on the tariff philosophy followed by the Government. Social, political and economic considerations exert pressure on the tariff philosophy because of which there is no uniformity in tariff structure in different states, though the approach used by different states has a lot in common. With the advent of reforms, economic considerations are gaining an upper hand. The electricity consumers pay these costs as well as profits on the investments made by the utility and the tax on profit.

Table No. 5.1

Cost and Energy Flows in the Power Sector

Items	Generation	Transmission	Distribution
Million Units passed on / sold	44393	41285	33458
Cumulative cost (Rs. Cr.)	7591	8805	10254
Cumulative Unit Cost (Rs./Unit)	1.71	2.13	3.06

Source: Tariff order of AP Electricity Regulatory Commission(APERC), March 2003

The table 5.1 shows the electricity sold and the cost of electricity at the generation, transmission and distribution stages. The calculation is based on the actual numbers of a state utility for the year 2003-04. The units passed on keep decreasing because of losses in transmission and distribution segments. The cumulative costs include the cost incurred by that and previous segments. The last row in the table shows the cumulative unit cost (i.e. Costs of all previous stages divided by the units sold to the next segment). Generation refers to the state owned generation wing which is a mix of low cost hydro and coal based plants, power purchase from IPPs and Central Generating Stations (CGS). Looking at the first row, it can be seen that the transmission loss = [(44393-41285)/44393] is around 7 %.

In the distribution segment, the units sold reduce substantially due to high distribution losses. Distribution loss = [(41285-33458)/41285] as around 19 %. In the second row, we can see that the largest share of cost paid by consumers attribute to generation. The tariff determination as per the provisions of Electricity Act 2003 require that consumer tariffs are set such that reasonable costs of Utility are fully recovered through tariff. As a result, at the consumer end all costs and all losses add up.

The numbers mentioned above can change substantially from state to state or region to region. The T&D loss as percentage of generation in the above example is seen to be 24.6 % ie. [(44393-33458)/44393]. The T&D loss figures of most utilities range between 20 to 40 %.

The following inferences can be made from the above table:

- The largest share of cost usually comes from generation.
- The largest share of leakage comes from distribution
- Consumers pay for both
- Such analysis helps in identifying focus areas needing attention.

When we add the allowed profit and income tax of the utility to its costs, the cost plus recoverable profit is called the Annual Revenue Requirement (ARR) of the utility. ARR is the common term used in the regulatory process and it has a direct impact on the average tariff of consumers.

5.2 Regulatory Review

Before the establishment of Regulatory Commissions, State Electricity Boards (SEBs) were authorised to set consumer tariffs so as to achieve a surplus of 3 % on value of fixed assets. In practice, the state governments approved the tariffs without seriously questioning SEBs efficiency or costs. The state regulatory commission now has the responsibility and authority of deciding tariff and is also a countervailing authority to decide what costs are reasonable. Regulatory Commission takes a detailed review of the performance of Utility (KSEB in Kerala) and also holds public hearings to gather evidence and opinion.

Typically, the process of regulatory review has the following parts:

1. The Utility files a tariff application a few months before the start of a financial year. The data for the ongoing year are used to project the sales, performance and costs for the next year.

2. The RC checks the utility's application for consistency and sufficiency of data. This process is called 'Technical Validation'. If additional data or corrections are required, the RC directs the utility to file a revised application.

3. The RC then publishes the corrected application (or tariff petition) and invite objections from public.

4. Based on the objections, feedbacks and comments of public, through public hearing or otherwise, the commission analyses the logic and reasonability of various issues.

5. Finally, the RC gives an order, wherein the logic of RC's decision is spelt out.

There are different methods to regulate utilities tariffs. The most common method is the 'Cost Plus' method.

5.2.1 Cost-Plus Method

In this method, the commission examines all costs incurred by the utility. Based on the evidence produced before the commission (by consumers or commission staff), it may conclude that some of the costs are not reasonable and may disallow these. The disallowed expenses are not counted as expenses of the utility and hence not passed on in the consumer tariff. Based on legal norms the commission allows the utility to add its profit to the approved costs. Approved costs plus the profit is then called Annual Revenue Requirement (ARR). Hence the term 'cost-plus' or cost +'. The income tax is considered as an expense of the utility and is recovered from the consumers as per the Indian regulations.

There are some advantages and also some limitations of this method. Some of the limitations are:

1) **Time consuming process:** Some have argued that this entails an in-depth review of all costs, which can be a time consuming process.
2) **Information asymmetry:** The utility controls data and tends to resist giving key data / information. So it invariably ends up being a struggle to get correct and useful data.
3) **Lack of incentive to the utility:** Annual tariff reviews pass on the costs/ benefits immediately to the consumers. The benefit of improved efficiency or the (cost of) lack of efficiency is passed on to consumers. Hence, there is little incentive for a utility to improve efficiency.
4) **Tendency to over invest:** A utility's profitability generally increases if it invests more in (capital) assets, leading to what is called 'gold plating' of investments. This phenomenon is a well-established concept in Regulatory Economics called as the Averch-Johnson Effect (A-J Effect)[1].

The key idea in Averch and Johnson's 1962 paper is that because allowed profit varies directly with the rate base (capital), the firm will tend to substitute too much capital for other inputs.

In practice, a pure cost-plus method is rarely applied. Usually, the RC examines the expenditure against two tests (i) usefulness and (ii) prudence of expenditure. The usefulness test examines if the said expense was necessary and whether it has achieved its stated benefit. The prudence test is an evaluation of

[1] H. Averch and L. Johnson. "The Behavior of the Firm Under Regulatory Constraint," American Economic Review, December 1962.

CHAPTER – 6

TARIFF REGULATORY FRAMEWORK IN KERALA

6.1 Introduction

This chapter deals with the electricity tariff regulatory frame-work in Kerala state vis-à-vis functioning of Kerala State Electricity Regulatory Commission (KSERC) and discuss the enabling regulations which have been framed by the State Commission to determine power tariff of generating companies, the Electricity Board or a licensee in pursuance of the provisions of Electricity Act 2003.

6.2 The Organization of Regulatory Commission

With the policy of encouraging private sector participation in Generation, Transmission and Distribution and the objective of distancing the regulatory responsibilities from the Government to the Regulatory Commissions, the need for harmonizing and rationalizing the provisions in the Indian Electricity Act, 1910, the Electricity (Supply) Act, 1948 and the Electricity Regulatory Commission Act 1998 in a new self contained comprehensive legislation arose. On the basis of the above objective, the Electricity Act 2003 has been enacted and the provisions of the Act have been brought into force with effect from the 10th of June 2003.

Kerala State Electricity Regulatory Commission was constituted vide Government Order G.O.(Ms).No.34/ 2002/PD dated 14 November, 2002 notified in the Government of Kerala Gazette, Extra-Ordinary dated 18 November, 2002

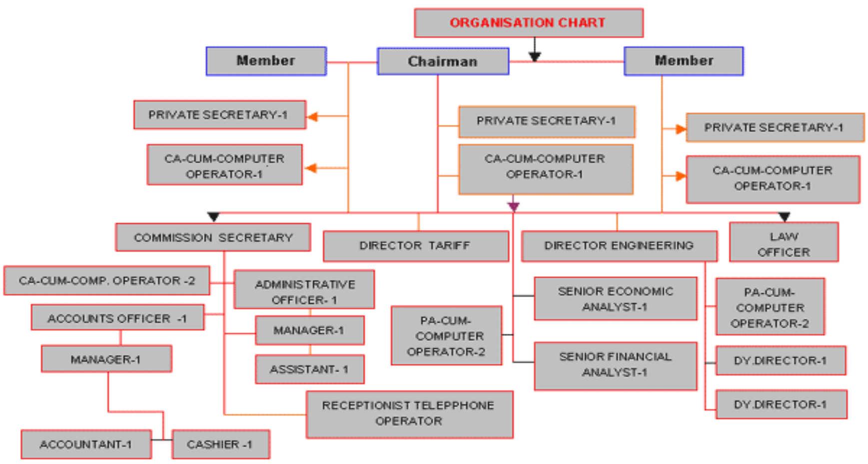
The Kerala State Electricity Regulatory Commission is a quasi-judicial body corporate having perpetual succession and a common seal, with power to acquire, hold and dispose of property, both movable and immovable, and to contract and shall, by the said name, sue or be sued. With effect from 10 June, 2003, the Commission has come under the purview of the Electricity Act, 2003, as the Electricity Regulatory Commissions Act, 1998 has since been repealed.

The Commission consists of Chairman and two Members. In recognition of the need for multi-disciplinary approach while addressing issues related to independent regulation, the statute prescribes that the Chairman and Members shall be persons of ability, integrity and standing who have adequate knowledge of, and having shown capacity in dealing with problems relating to engineering, finance, commerce, economics, law or management. The Chairman and Members are appointed by the Government of Kerala on the recommendation of a Selection Committee constituted by the State Government as prescribed under the statute. The statute also provides for the appointment of a Secretary, functioning under the Commission, whose powers and duties are defined by the Commission.

The Commission, as per the powers vested in the Electricity Act 2003, has formulated the Kerala State Electricity Regulatory Commission (Tariff) Regulations 2003. As per the regulation, the Board has to submit "the Aggregate Revenue Requirement and Expected Revenue from Charges (ARR & ERC) " for the ensuing year before the Commission. Accordingly, the Board is submitting its tariff petitions on the Aggregate Revenue Requirement and Expected Revenue from Charges (ARR & ERC) right from 2003-04.

Figure No. 6.1

Organisation Chart of KSERC



Source: KSERC, Trivandrum

6.3 Functions of the Commission

The Commission is vested with the responsibility of discharging the following functions:

(a) Determine the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State;

(b) Regulate electricity purchase and procurement process of distribution licensees including the price at which electricity shall be procured from the generating companies or licensees or from other sources through agreements for purchase of power for distribution and supply within the State;

(c) Facilitate intra-State transmission and wheeling of electricity;

(d) Issue licenses to persons seeking to act as transmission licensees, distribution licensees and electricity traders with respect to their operations within the State;

(e) Promote cogeneration and generation of electricity from renewable sources of energy by providing suitable measures for connectivity with the grid and sale of electricity to any person, and also specify, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee;

(f) Adjudicate upon the disputes between the licensees and generating companies and to refer any dispute for arbitration;

(g) Levy fee for the purposes of the Electricity Act, 2003;

(h) Specify State Grid Code;

(i) Specify or enforce standards with respect to quality, continuity and reliability of service by licensees;

(j) Fix the trading margin in the intra-State trading of electricity, if considered, necessary;

(k) Discharge such other functions as may be assigned to it under the Electricity Act, 2003;

(l) Advise the State Government on all or any of the following matters, namely:–

(m) Promotion of competition, efficiency and economy in activities of the electricity industry;

(n) Promotion of investment in electricity industry;

(o) Re-organization and restructuring of electricity industry in the State;

(p) matters concerning generation, transmission, distribution and trading of electricity or any other matter referred to the State Commission by the State Government.

6.4 The Mission of the Commission

The mission of the Commission is:

a) To promote competition, efficiency and economy in the activities of the Electricity Industry within the State of Kerala.

b) To regulate the power purchase and procurement process of the distribution licensees for sale, distribution and supply of electricity within the State of Kerala.

c) To determine the tariff for generation, transmission, wheeling and supply of electricity, wholesale, bulk or retail, as the case may be, within the State of Kerala.

6.5 Objectives of Tariff determination by KSERC

As per subsection (5) of Section-62 of the Electricity Act, 2003 (Central Act No. 36 of 2003) the Commission may require a generating company or licensee to comply with such procedure as may be specified in calculating the expected revenue from the tariff and charges which he or it is permitted to recover. Application for determination of tariff shall be made by a Generating Company, the Board or a licensee in accordance with the provisions of Subsection (1) of Section 64 of the Act.

The regulations have been framed in pursuance of the above provisions of the Act. In designing the scheme contained in the regulations, the Commission expects to achieve the following objectives:-

a) To inform Generating companies, the Board or licensees of the basic minimum data on information requirements for seeking the Commission’s approval to the expected revenue from charges and for any proposal of modification of the tariffs;

b) To provide standardised formats in which such information is to be provided;

c) To specify the procedure by which the Commission would take up the ERC filings and Tariff filings for its consideration and appropriate orders thereon; and

d) To ensure the greatest possible transparency in such procedure and the fullest possible opportunity for all concerned to participate in such a process.

6.6 Procedure for Annual ERC filing

1. Not later than 4 months before the commencement of any financial year, generating companies, the Board or licensees shall provide to the Commission full details of its calculations for the ensuing financial year of the ERC for that year.

2. The details of calculations of ERC and other related information shall be provided in the format prescribed and shall be provided for each of the financial years as directed by the instructions given in each of these formats.

3. Where any entity holds more than one category of license, the details in the prescribed formats have to be filed separately in respect of each license.

4. The details of calculations of ERC in the prescribed formats have to be filled by the Generating Companies, Board or licensee in 6 sets with each format being signed by an authorised officer of Generating Company, the Board or licensee respectively who shall be responsible for verifying and certifying the correctness thereof. In addition to the hard copies of the ERC formats, Generating Company, the Board or licensee has also to furnish the said formats in electronic form in disc using the MS Excel spreadsheet package.

5. The ERC filed by Generating Company, the Board or licensee will be scrutinised by the Commission and as a result of such scrutiny, the Commission may, within 15 working days, call for such further information and clarifications, as it may deem fit.

6. The ERC filed by Generating Company, the Board or licensee will be treated as a petition upon the Commission deciding that all the information and clarifications sought for by it have been produced to the satisfaction of the Commission. Generating Company, the Board or licensee will thereafter be informed of this decision.

7. The Commission will thereafter follow, as far as may be practicable, the procedure specified in the General Regulations for hearing on the ERC filing and for passing orders.

6.7 Procedure for Tariff filing

1. The Commission may, on its own, on being satisfied that there is need to review the tariff of a Generating Company, the Board or any other licensee, shall initiate the process of review in accordance with the procedures set out para 6.10 below.

2. If Generating Company, the Board or licensee desires to amend the current tariff, it shall prepare and lodge with the Commission its application for amendments, provided that no tariff or part of any tariff shall be amended more than once in any financial year. Provided further that the application for amendment of tariff shall be filed not later than 4 months before the intended date of implementation of such amended tariff.

3. The application for amendment of tariff may be filed along with ERC filing or at any later date.

4. The details of calculations of proposed tariff by the Board or licensee shall be in the prescribed formats and have to be filed in 6 sets with each format being signed by an authorised officer of the Board or licensee who shall be responsible for verifying and certifying the correctness there of. In addition to the hard copies of the formats, it is also necessary to furnish the said formats in electronic form in disc using the MS Excel Spread sheet package.

5. Generating Company's, Board's or licensee's application for amendment of tariff shall contain the following:

   a) A statement of the current tariffs and charges, that are proposed to be amended, together with all applicable terms and conditions;

   b) A statement of amendments proposed with the proposed tariffs and proposed terms and conditions;

c) A statement of the estimated change in the annual gross revenue that would result in the ensuing financial year, from the proposed amendments, stated in rupees and as percentage of annual revenue from existing tariffs. The change in annual revenue for the Board or licensee should be shown as a whole and for each tariff category affected;

d) Following additional information in respect of the Board or distribution licensee:

   i) An embedded cost study showing the cost of service of supply of electricity to each consumer category;

   ii) An analysis of the effect of the proposed tariff changes on the average as well as typical small, medium and large consumers in each affected tariff category and the changes in annual bills and monthly bills by season (where applicable) in both rupees and percentage terms;

   iii) A statement of any proposed cross subsidy including the amount of such subsidy to the affected consumer category and the source of offset of this subsidy (e.g. other consumer category/categories);

   iv) A comparison of the percentage of cost of service expected to be recovered in the ensuing financial year by the current and proposed tariff for each consumer category;

   v) A statement of any subsidy committed by the Government of Kerala to the consumers to whom it is directed and the way in which such subsidy is proposed to be reflected in the proposed tariff applicable to these consumers;

   vi) A written explanation of the rationale for the proposed tariff changes, including justification of the rate of return being proposed

   vii) Any other information as required by the Commission.

6. Within 15 working days of the receipt of the Tariff filing, the Commission shall notify Generating Company, the Board or licensee whether any additional information is required by the Commission to assess Generating Company's Board's or licensee's calculation, specifying the date by which such information is to be filed.
7. The filled up formats filed by Generating Company, the Board or licensee will be treated as a petition upon the Commission deciding that all the information and clarification sought for by it have been produced to the satisfaction of the Commission.
8. The Commission will there after follow, as far as may be practicable, the procedure specified in para 6.10 below for hearing on the Tariff filing and for passing orders thereon

6.8 Publication of petition

The Generating Company, the Board or licensee shall arrange for publication of the petition on ERC filing or Tariff filing in the following manner:

(a) The summary of the petition, in such format, as may be approved by the Commission shall be published in one issue each of two daily newspapers in English language and two daily newspapers in Malayalam language having wide circulation in the State. The advertisement should invite interested persons to file their objections and such documents as they seek to rely upon supported by an Affidavit, in six copies, within the date as specified by the Commission and also indicate whether they would like to be heard in person by the Commission.

(b) The advertisement shall also specify that interested persons may inspect the copies of the petitions in specified offices of Generating Company, the Board or licensee during normal working hours within 10 working days of the publication of the notice and also obtain the salient features of the petition at such specified places.

(c) The advertisement shall also mention that the full set of the petition / application together with supporting material would be made available at the specified offices of Generating Company, the Board or licensee to any interested person who may ask for it on payment of cost of photocopying.

6.9 Commission's powers for verification

(1) The Commission may get the books and records of Generating Company, the Board or licensee concerned examined by its officers and/or by consultants and/or by any authorized person at any point of time during the pendency of the petition or otherwise. The report of the officers / consultants / or authorized person shall be made available to the parties concerned and they shall be given opportunity to react on the reports. The Commission shall duly take into account the report or the opinion given by the officers and/or by consultants or any authorised person and the reply filed by the parties while deciding the matter, and if considered necessary, the examination before the Commission of the person giving the report or the opinion.

(2) Generating Company, the Board and licensee shall submit periodic returns, as may be prescribed containing operational and cost data to enable the Commission to monitor the implementation of its order and reassess the basis on which tariff was approved.

(3) All filings should be in conformity with the conditions of license, in the case of a licensee.

6.10 Saving of inherent power of the Commission

1) Nothing in these Regulations shall be deemed to limit or otherwise affect the inherent power of the Commission to make such orders, as may be necessary for meeting the ends of justice or to prevent abuse of the process of the Commission.

(2) Nothing in these Regulations shall bar the Commission from adopting, in conformity with the provisions of the Act, a procedure, which is at variance with any of the provisions of these Regulations, if the Commission, in view of the special circumstances of a matter or class of matters and for reasons to be recorded in writing, deems it necessary or expedient for dealing with such a matter or class of matters.

(3) Nothing in these Regulations shall expressly or impliedly bar the Commission dealing with any matter or exercising any power under the Act for which no Regulation have been framed and the Commission may deal with such matters, powers and functions in a manner it deems fit.

6.11 Relevant provisions in the Central Act to empower regulation:

By the enactment of Electricity Act –2003 and by force of the relevant provisions contained in the Act and by force of the provisions in the National Electricity Policy-2005 (NEP-2005) and National Tariff Policy 2006 (NTP-2006) the central and state regulatory commissions have been provided with sufficient legitimate rights and power to enforce an independent regulatory regime to make country’s power sector more vibrant.

6.11.1 Electricity Act – 2003

It is stated in the preamble of the Electricity Act-2003 : ‘It is an Act to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity and generally for taking measures conducive to development of electricity industry, promoting competition therein, protecting interest of consumers and supply of electricity to all areas, rationalisation of electricity tariff, ensuring transparent policies regarding subsidies, promotion of efficient and environmentally benign policies, constitution of Central Electricity Authority, Regulatory Commissions and establishment of Appellate Tribunal and for matters connected therewith or incidental thereto.”

6.11.2 Key provisions in EA-2003

Section 61. The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:-

a) The principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;

b) The generation, transmission, distribution and supply of electricity are conducted on commercial principles;

c) The factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments

d) Safeguarding of consumers interest and at the same time, recovery of the cost of electricity in a reasonable manner;

e) The principles rewarding efficiency in performance

f) Multi year tariff principles;

g) That the tariff progressively reflects the cost of supply of electricity and also reduces cross subsidies in the manner specified by the Appropriate Commission;

h) The promotion of co-generation and generation of electricity from renewable sources of energy;

i) The National Electricity Policy and tariff policy:

6.11.3 National Electricity Policy

Section 3 (1) of the Act, requires the Central Government to prepare the National Electricity Policy and the National Tariff Policy to guide the development of the electricity sector of the country in an optimal manner to achieve the objectives of the Act. The Government of India notified the National Electricity Policy 2005 on 12th February 2005, and the introductory section elaborates on (a) the importance of electricity to economic development of the country, (b) attendant social benefits of economic development, (c) problems plaguing the sector, (d) reiterates the intent of the Act, and (e) the intent of the NEP05.

Relevant sections of the National Electricity Policy - 2005, which are applicable to the functions of State Commission, are given below:

Section 1.2: "Electricity is an essential requirement for all facets of our life. It has been recognized as a basic human need. It is a critical infrastructure on which the socio-economic development of the country depends. Supply of electricity at reasonable rate to rural India is essential for its overall development. Equally important is availability of reliable and quality power at competitive rates to Indian Industry to make it globally competitive and to enable it to exploit the tremendous potential of employment generation. Services sector has made significant contribution to the growth of our economy. Availability of quality supply of electricity is very crucial to sustained growth of this segment".

Section1.4: "Indian Power sector is witnessing major changes. Growth of Power Sector in India since its Independence has been noteworthy. However, the demand for power has been outstripping the growth of availability. Substantial peak and energy shortages prevail in the country. This is due to inadequacies in generation, transmission & distribution as well as inefficient use of electricity. Very high level of technical and commercial losses and lack of commercial approach in management of utilities has led to unsustainable financial operations. Cross-subsidies have risen to unsustainable levels. Inadequacy in distribution networks has been one of the major reasons for poor quality of supply".

Section 1.6: "Electricity Act-2003 provides an enabling framework for accelerated and more efficient development of the power sector. The Act seeks to encourage competition with appropriate regulatory intervention. Competition is expected to yield efficiency gains and in turn result in availability of quality supply of electricity to consumers at competitive rates".

Section 1.8: "The National Electricity Policy aims at laying guidelines for accelerated development of the power sector, providing supply of electricity to all areas and protecting interests of consumers and other stakeholders keeping in view availability of energy resources, technology available to exploit these resources, economics of generation using different resources, and energy security issues".

6.11.4 National Tariff Policy

The Government of India notified the National Tariff Policy-2006 on 6th January 2006, in continuation of the National Electricity Policy-2005. The National Tariff Policy-2006 reiterates the importance of providing reliable supply of electricity, and reasonable rates to consumers to ensure rapid economic development, and attendant social benefits.

Relevant sections of the National Tariff Policy - 2006 in support of the above and as applicable to State Commission are given below:

Section 1.3. "It is therefore essential to attract adequate investments in the power sector by providing appropriate return on investment as budgetary resources of the Central and State Governments are incapable of providing the requisite funds. It is equally necessary to ensure availability of electricity to different categories of consumers at reasonable rates for achieving the objectives of rapid economic development of the country and improvement in the living standards of the people"

Further, it lays out the critical challenge of the regulatory process – ensuring reasonable rates for electricity, whilst attracting sufficient investment to the sector and promoting a consistent regulatory approach across the country.

Section 1.4 – "Balancing the requirement of attracting adequate investments to the sector and that of ensuring reasonability of user charges for the consumers is the critical challenge for the regulatory process. Accelerated development of the power sector and its ability to attract necessary investments calls for, inter alia, consistent regulatory approach across the country. Consistency in approach becomes all the more necessary considering the large number of States and the diversities involved".

The legal position of the NTP-06 is laid out clearly in the NTP-06, and requires the CERC and SERCs to be guided by the NTP-06 in discharging their functions, including in framing the regulations under Section 61 of the Act.

Relevant extracts of the NTP-06 in support of the above are given below:

Section 2.2: "The Act also requires that the Central Electricity Regulatory Commission (CERC) and State Electricity Regulatory Commissions (SERCs) shall be guided by the tariff policy in discharging their functions including framing the regulations under section 61 of the Act".

Section 2.3: "Section 61 of the Act provides that Regulatory Commissions shall be guided by the principles and methodologies specified by the Central Commission for determination of tariff applicable to generating companies and transmission licensees".

Section 2.4 "The Forum of Regulators has been constituted by the Central Government under the provisions of the Act, which would, inter-alia, facilitate consistency in approach especially in the area of distribution".

6.11.5 Regulations by CERC & KSERC

Following from the provisions of the Act the CERC had notified the Central Electricity Regulatory Commission (Terms & Conditions of Tariff) Regulations 2004 on 26th March 2004. The Forum of Regulators (FOR) was constituted vide Notification dated 16th February, 2005 in pursuance of the provision under section 166(2) of the Electricity Act 2003, to facilitate consistency in approach, especially in the area of distribution.

Following from the provisions of the Act, National Electricity Policy – 2005 & National Tariff Policy – 2006, the KSERC has notified the following regulations relating to tariff:

(a) The Kerala State Electricity Regulatory Commission (Tariff) Regulations 2003 on 3rd January 2004

(b) The Kerala State Electricity Regulatory Commission (Terms & Conditions of Tariff for Retail Sale of Electricity) Regulations 2006 on 23rd March 2006

(c) The Kerala State Electricity Regulatory Commission (Terms & Conditions for Determination of Tariff for Distribution and Retail Sale of Electricity under Multi-Year Tariff (MYT) framework) Regulations 2006 on 12th October 2006

(d) As stated in the Central Electricity Regulatory Commission (Terms & Conditions of Tariff) Regulations 2004 dated 26th March 2004, the term of the regulations was 5 years, unless otherwise reviewed by the CERC prior to that. Accordingly the CERC has now notified the Central Electricity Regulatory Commission (Terms & Conditions of Tariff) Regulations 2009 dated 19th January 2009, that came into effect on 1st April 2009. The list of regulations notified by the Kerala State Electricity Regulatory Commission is given in Annexure – II.

A Comparative analysis of Tariff Regulatory Policies (Historical Back ground of Legislative and Regulatory Initiatives) is given in Annexure VI.

CHAPTER – 7

A CASE OF POWER TARIFF HIKE WITH RESPECT TO A POWER INTENSIVE CONSUMER IN KERALA

7.1 Introduction

Indian Aluminium Company Limited (presently known as Hindalco Industries Limited), Alupuram Smelter, India's first primary aluminium smelter was set up at Alupuram, Kalamassery in Kerala with an initial annual capacity of 2500 T primary aluminium metal in the year 1943, by the joint initiative of His Highness the Maharaja of erstwhile Travancore and Aluminium Company of Canada (ALCAN). The plant at Alupuram was continuously expanded to reach an annual capacity of 21500 Tonne by 1989. In fact, the then Dewan of Travancore State Sir. C. P. Ramaswami Iyer had initiated discussions with ALCAN, Canada during late 1930s and entered into an agreement with Indian Aluminium Company on 13 July 1941 to supply cheap electric power generated from the first hydroelectric plant of Travancore State called Pallivasal Hydroelectric Project and further facilitated setting up of all infrastructural facilities required to commence production of primary aluminium metal at Alupuram Smelter. Since aluminium metal is produced by power intensive electrolytic reduction of aluminium oxide (alumina, the purified form of bauxite), it was a well thought out and planned decision by the Maharajah of erstwhile Travancore to invite a multi-national aluminium company to set up a power intensive aluminium smelter to ensure evacuation of power generated at Pallivasal, at a time when there were not much consumers for electricity and the transmission and distribution network in the state was at the infant stage. The setting up Indian Aluminium Company Limited at Kalamassery, Kerala by the multinational aluminium giant ALCAN can be regarded as the first global investment initiative of its kind in the erstwhile Travancore or in the whole of Kerala. The success of Pallivasal project paved the way for its progressive expansion and further growth of State's power sector.

Indian Alumium Company Limited (INDAL), Alupuram Smelter (now Hindalco Industries Limited, an Aditya Birla Group company) has been part of India's Aluminium Industries for over six decades. Established in 1938 at Belur, West Bengal, the Company is vertically integrated through all stages of Aluminium business – from Bauxite mining, Alumina refining, power generation, Aluminium Smelting, to the manufacture of semi fabricated products of Sheet, Foil, Extrusion, wire rods, alloy ingots and Aluminium Scrap remelting. Till June 2000 INDAL was operating as an Indian subsidiary of ALCAN Canada, and it has been taken over by Aditya Birla Group as a subsidiary of Hindalco Industries Limited and subsequently merged with Hindalco Industries Limited with effect from 7 March 2004.

INDAL's alumium metal manufacturing pot lines (Line-I with an amperage of 25kA and Line-II with an amperage of 50kA) were closed one after the other due to the spiraling increase in cost of production on account of unaffordable electricity charges. INDAL was the single largest consumer of electricity in Kerala State till the closure of Smelter unit.

7.2 Brief history of the company under study

7.2.1 Growth of Alupuram Factory

The Alupuram Smelter was commissioned in the year 1943, with an initial installed capacity of 2500 TPA with 25 KA pot line. The most important raw material required for the electrolytic reduction of alumina (purified form of bauxite ore) into aluminium metal is electricity, which was supplied from Pallivasal Hydroelectric Project, Kerala's first Hydel power station. This is the first Aluminium smelter in India. Over the years, it has undergone several expansions including the addition of 50 KA pot lines and has reached the capacity of 21500 TPA during the year 1983. The growth of power sector and industrialisation in Kerala was tantamount with the gradual expansion of Alupuram smelter during first three decades of operation of Alupuram smelter from its inception. The 25 KA line having 7500 TPA capacity was de-energised in 1996 due to economic unviability on account of excessive power tariff and subsequently the plant was shutdown. The total plant capacity was then reduced to 14000 TPA.

The alumina required for the process was received from INDAL's own alumina plants at Belgaum (Karnataka) and at Muri (Bihar). Other major raw materials required for the process like cryolite, aluminium fluoride, petroleum coke, pitch, furnace oil, etc. were either imported or purchased from indigenous sources. The aluminium production process is a high temperature electrolytic reduction process, wherein the alumina dissolved in molten cryolite undergoes electrolysis by using carbon electrodes. The electrical energy required for the process was supplied by KSEB. About 17000 units of electrical energy are required to produce one tonne of aluminium. The monthly power consumption corresponding to 21500 TPA of primary aluminium metal production was more than 30 million units till the closure of line-I pot room in 1996 and that corresponding to 14000 TPA of metal production was more than 20 million units per month.

7.2.2 Products

The primary product of Alupuram smelter was molten Aluminium metal, which was cast in to billets, ingots, alloy ingots or wire rods as per the requirements at our Casting plant. When there was shortage of primary metal it was also procured from other Hindalco units or from the market to meet Casting Plant requirement. Billets were cast in to 6", 9" and 12" diameter sizes and supplied, as per the requirement of Hindalco Alupuram Extrusion Unit. Aluminium ingots weighing 20 Kg (1-20K) and 10 Kg (1-10K) were cast and sold to external customers. The extruded products to serve different industrial and architectural applications and ingots were used for the manufacture of sheets, automobile parts etc. The Extrusion Plant at Alupuram is now working and Casting Plant is supplying aluminium sawn billets to extrusion plant. Wire rods produced were sold to external customers. The carbon electrode paste for electrolysis was manufactured at the Carbon plant. A part of the Carbon paste was to external parties as per market demand. The main product, viz. billets are used for the manufacture of extruded aluminium

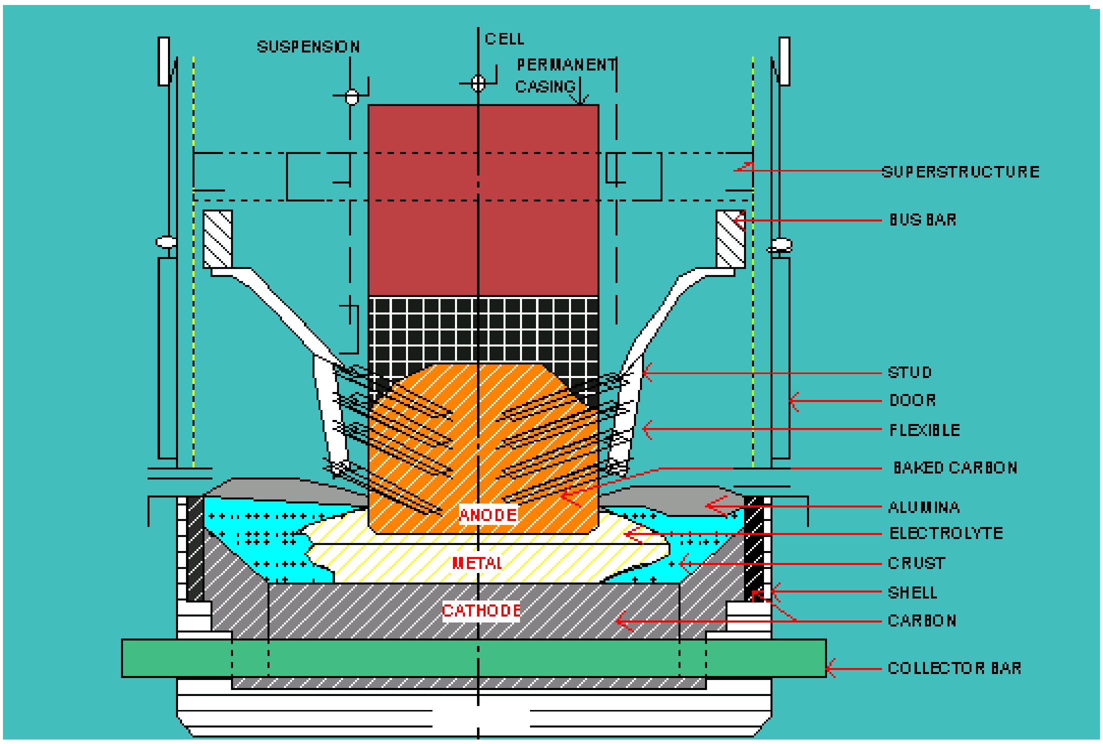
7.2.3 Operations

7.2.3.1 Pot Room

The heart of Aluminium smelter is the Electrolytic cell or Pot. The typical design and technology used for Alupuram pots is categorised as HSS Technology (Horizontal Stud Soderberg). The pots are arranged in rows called Pot line and electrically connected in series. The electric supply to the pots is direct current. Electric power from KSEB's 110 kV supply system is directly drawn to Company's 110 kV sub-station, stepping down to 11 KV and fed to a silicon rectifier station for converting AC power into DC power. The carbon block lining at the bottom of the cell acts as the cathode and anode is the baked carbon supplied by Carbon Paste plant.

Figure No. 7.1

Typical arrangement of Electrolytic cell for making aluminium



Source: Electrochemistry of Aluminium – ALCAN Report

The electrolyte consists of alumina dissolved in Cryolite. Alumina is added intermittently to maintain the concentration of dissolved Alumina within the desired range. The molten Aluminium is withdrawn intermittently from the bottom of the cells by using pneumatic suction equipment called vacuum crucible. Pot room was de-energised on 1 August 2003 due to economically unviable operations consequent upon the tariff hike imposed from October 2002 by the Government / KSEB. Figure No. 7.1 shows typical arrangement showing various components of an HSS Electrolytic Cell, which is also called HSS pot.

7.2.3.2 Casting Plant

The Aluminium metal drawn from the Pot room and /or the cold metal sourced from other Hindalco units is fed to the Casting plant furnaces. When molten metal from pot room was available, the oil heating required in furnaces was limited to the purpose of holding metal in molten stage and for melting aluminium scrap generated in extrusion and casting plants. Molten metal is cast either as billets / alloy ingots, CG/EC grade ingots or as wire rods. In the case of billets and alloy ingots, which are basically Aluminium alloys, alloying materials are added at desired levels and cast as billets/ ingots. The as cast billets are homogenized, ultrasonically tested for cracks and the defect free billets are cut into desired length and are transferred to Extrusion plant for the manufacture of Extruded sections. Extruded products are sold in the Indian markets and some special products are exported. The Alloy Ingots / ingots/ wire rods are sold to Indian customers or exported.

7.2.3.3 Carbon Paste plant.

Carbon electrode paste is used as anode at the Pot rooms and this is manufactured in this plant. The raw materials used are coal tar pitch and calcined petroleum coke. Coke of different fractions and molten pitch at a fixed formulation is mixed at the mixer at the desired temperature and it is either sent directly to Pot rooms or cast in drums as sales paste. The sales paste is sold to third parties. This was shut down effective September 2003 consequent to Pot room de- energisation.

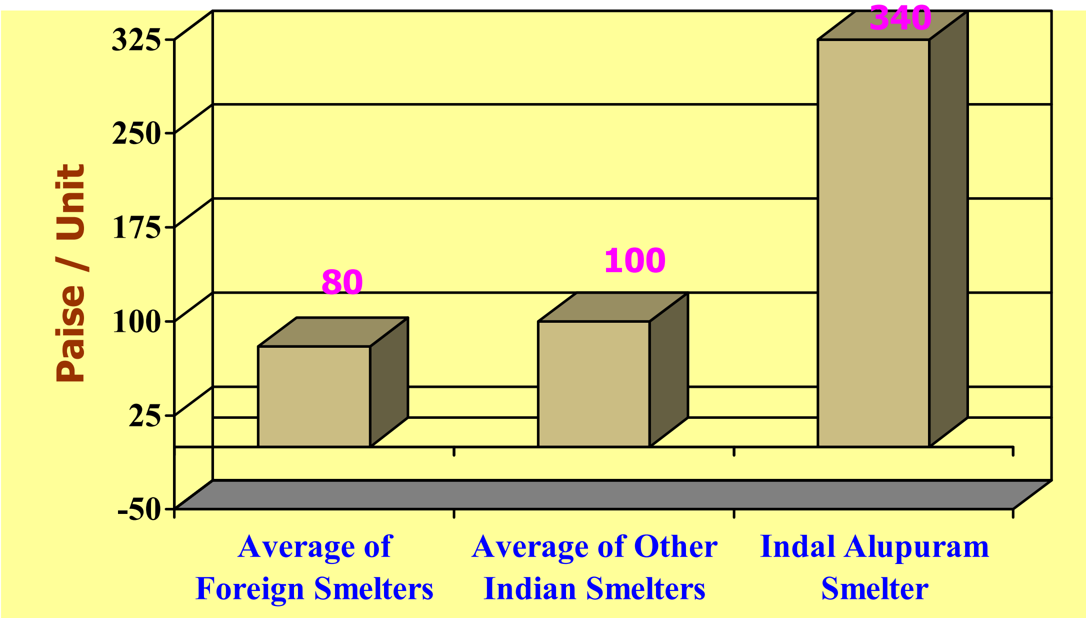
7.3 Power Tariff increase and viability crisis

As mentioned earlier, the most important factor in selecting Alupuram as the location of Smelter unit, even though located far away from Bauxite mines, was the cheap electricity made available by the State, as power development in Kerala was mainly Hydel. The growth of Hydel power continued at a reasonable pace till 1976, with the commissioning of Idukki power project. All major hydro development plans have since been held up due to environmental considerations. Of late, the State is turning increasingly towards thermal power from within the state or from Central generating stations (CGS) outside for meeting its growing energy demands even though the State has abundant resources of hydro potential and as a result, there has been a substantial increase in the power tariff in the State for the period from 1997 to 2002. This unaffordable electricity tariff forced INDAL to restrict the smelting capacity to 14000 Tonnes from 21500 Tonnes in the year 1996 as mentioned earlier.

Power is the main raw material for aluminium smelter and about 17000 units of energy is required for producing one Tonne of aluminium, which constitutes about 60% of the total production cost at the prevailing electricity tariff as applicable for EHT Industrial Electricity Consumers (Rs. 3.40 per Unit at the time of de-energisation of smelter unit on 1 Aug 2003) while for smelters abroad, the energy cost averages only about 20% of the cost of production. All major players in aluminium business, nationally / internationally, are supported by either Captive or Utility power at a unit cost of less than a rupee. The selling price of aluminium is independent of the cost of individual producers, being governed by the LME (London Metal Exchange) price and market conditions. Figure 7.2 shows comparison of power tariff as applicable to primary aluminium smelters India and abroad.

Figure No. 7.2

Comparison of Electricity tariff – Alumium smelters



Source: Annual report of INDAL for the year 2002-03

During the period from 1997 to 1999, the KSEB hiked the tariff 5 times, raising it from Rs. 1.12 per kWh to Rs. 2.40 per kWh. Effective 1 August 2001, KSEB hiked the EHT tariff by a further 25% and in that tariff order the State Government had agreed in principle to the long pending demand of bulk and power intensive HT/ EHT industrial electricity consumers to allow incentives on the basis of their merits of high power factor and high load factor vide Government order no. GO (MS) No. 20/2001/PD dated 3 August 2001. The KSEB had also agreed to consider the high load factor and high power factor of eligible industrial consumers to grant incentives as per Board order B.O.No. 1782/2001/778 (Plg. Com 4304/2001) dated 23 August 2001.

In the light of the above-mentioned orders, it was decided by the Company to sustain production operations expecting early orders by Govt. and KSEB to effect tariff incentives. But the Government and KSEB did not take a decision on the matter of incentives, despite the repeated requests and follow ups made by the Company Management, Trade Unions and Kerala HT and EHT Industrial Electricity

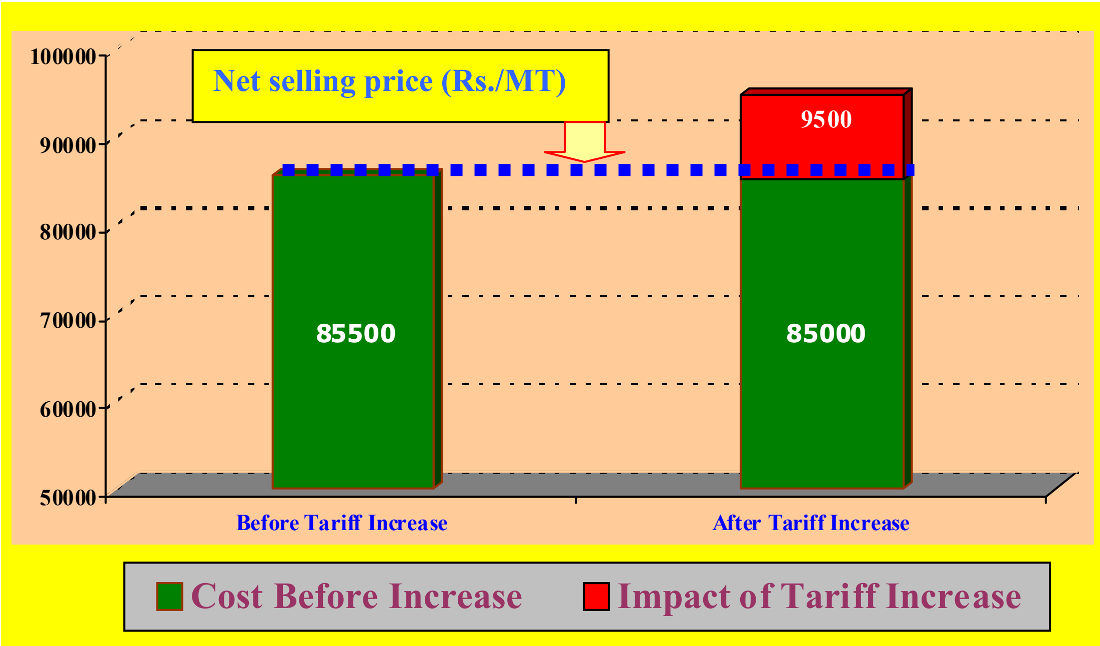
Consumers Association till 1 August 2003 (the date of de-energisation of line – II pot room).

When the Company was expecting a reasonable relief in tariff in the form of power factor and load factor incentives, to circumvent the effect of earlier hikes in electricity tariffs, the Government and KSEB effected another tariff hike by 50 paise per unit effective 1 October 2002. The tariff as applicable effective 1 October 2002 was Rs 3.40 per kWh. Being critically dependent on the power cost, where a hike of 10 paise per kWh increases the metal cost by about Rs 1700/- per Tonne, the Smelter has become completely unviable due to the oppressive hike in tariff. The hike in power has resulted in a monthly loss of Rs.2 Crores or an annual loss of Rs.24 Crores. Comparison of cost of production of primary metal before and after tariff hike is shown in figure no. 7.3 and impact of power tariff increase in the cost of productions is shown in figure 7.4.

The Company and Trade Unions made repeated requests and appeals to the KSEB as well as the Government of Kerala to fix a reasonable tariff taking into account the bulk and steady consumption, purpose of use of electricity as a raw material, the substantial monetary benefits to the State Government as well as the Central Government and local authorities by way of central excise duty, central sales tax, Kerala General Sales Tax, income tax and other local taxes. The annual electricity charge to KSEB was around **Rs. 68 Crores** before the tariff hike in October 2002. The tariff hike effected in October 2002 @ 50 ps. / unit imposed upon the company an additional burden of Rs. 12 Crores per year in electricity charges. The company was providing employment to more than 1000 and odd employees including indirect employment. Neither the KSEB nor the Government of Kerala has cared to study the impact of oppressive hike in electricity tariff on the economic unviability of smelting operations of INDAL, Alupuram.

Figure No. 7.3

Comparison of cost of production before and after the tariff hike imposed in October 2002

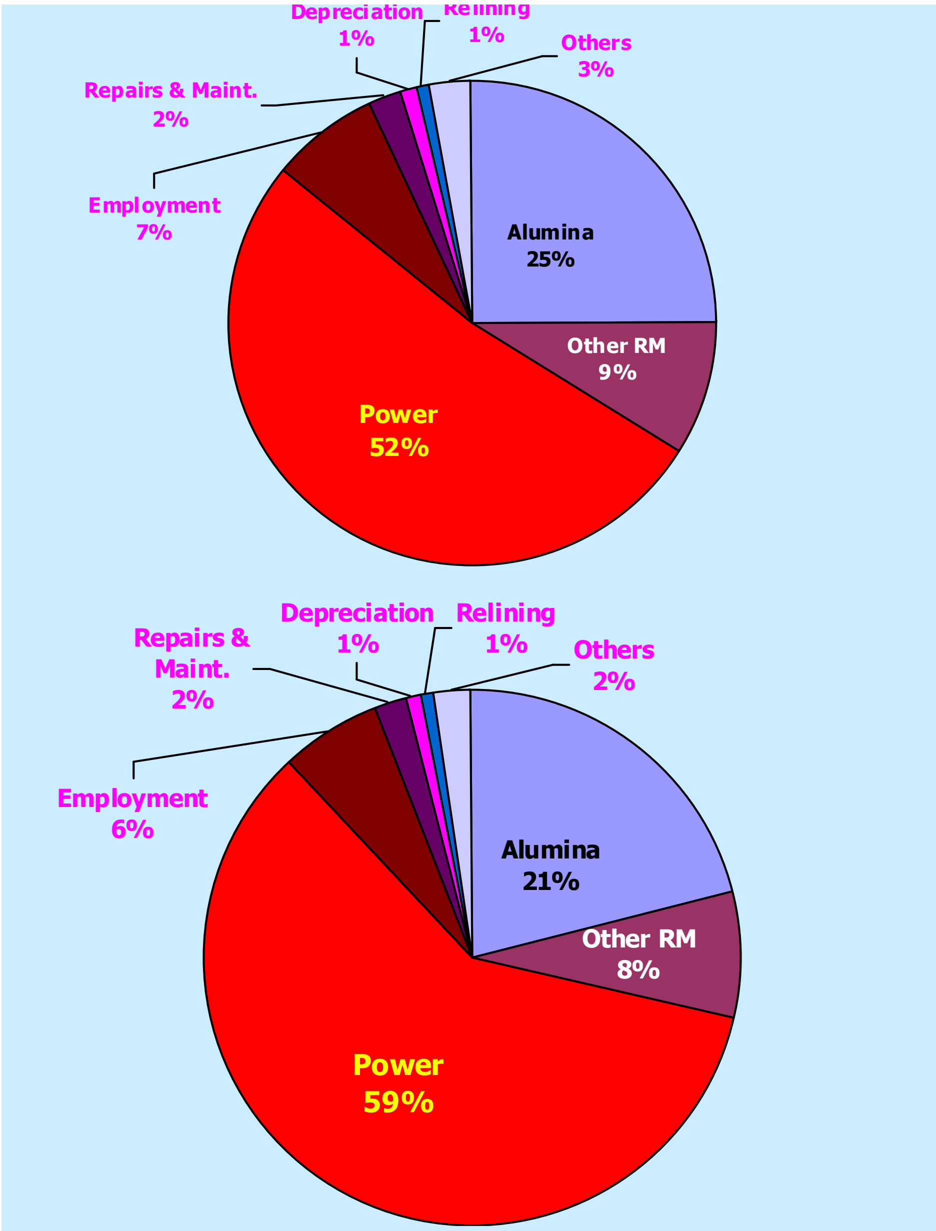


Source: Annual report of INDAL for the year 2002-03

Further, by repeated follow ups and representations given by the Company and Trade Unions of Hindalco smelter, the KSEB as well as the Government had accepted the ground realities and allowed a temporary relief for a short while of 3 months to the tune of Rs.1 Crore a month from January 2003 to March 2003 by a Govt. Order (Refer Annexure-III). This relief was given by the Government to enable INDAL to sustain operations in view of the plight of employees and their families likely to be affected in the event of a closure. After the expiry of three months, the company management and trade unions approached the Government and KSEB again praying for a permanent relief in tariff to the tune of 50 ps. / Unit as necessary solution to sustain production operations. But the KSEB and Government expressed its inability to allow any more relief beyond March 2003. By reason of mounting losses to the tune of about 1.2 Crores per month solely on account of unaffordable electricity tariff, the Company has been compelled to close down its smelting operations at its Smelter at Alupuram with effect from 1st August 2003 after surrendering the contract demand of about 30 MW of electricity under the agreement with the KSEB and by rendering about 343 permanent employees and hundreds of indirect employees including contract workers without any work.

Figure No 7.4

Split up of cost of production before and after the tariff hike



Source: Annual report of INDAL for the year 2002-03

From the figure 7.3, it can be seen that after the tariff increase in October 2002, the cost of production has increased by Rs 9500 / MT against the net selling price of primary aluminium metal. The monthly production of aluminium was 1200 MT and therefore the company was incurring a direct loss of Rs. (1200 x 9500), which amounts to Rs. 1.14 Crores on smelting operations alone. Other products like wire rods and alloy ingots were also making loss and thus total monthly loss was about Rs. 2 Crores. Cost structure of primary metal production before and after tariff hike is shown in figure no. 7.4. The relief allowed by Government was just sufficient for the company to keep its nose above water.

7.4 Absence of independent regulation (State Commission)

The Electricity Regulatory Commissions Act, 1998 was promulgated by the President of India as an ordinance and came into force on the 25 April 1998. This was an Act to provide for the establishment of a Central Electricity Regulatory Commission and State Electricity Regulatory Commissions, rationalization of electricity tariff, transparent policies regarding subsidies, promotion of efficient and environmentally benign policies and matters connected therewith or incidental thereto. Even though the Central Electricity Regulatory commission was constituted by the central government followed by constitution of State Electricity Regulatory Commissions by many states, the Government of Kerala did not constitute state commission till November 2002.

As per the ERC Act-1998, state commission is the sole authority to determine tariff in a scientific manner as per the tariff determination procedure deliberated in the previous chapters. The ERC Act-1998 empowers the Central and State Commissions to assume the role of an independent regulator and take suitable decisions on all matters related to electricity generation, transmission, distribution, purchase of power, fixing of retail and bilk tariff, open access etc in accordance with terms specified in the Act and to safeguard the legitimate interests of all stakeholders.

As section 29 (2) (e) of the Act, the State Commission shall determine by regulations the terms and conditions for the fixation of tariff, and in doing so, shall be guided by the following "the interests of the consumers are safeguarded and at the same time, the consumers pay for the use of electricity in a reasonable manner based on the average cost of supply of energy".

Further, as per Section 29 (3) of the ERC Act 1998, "the State Commission, while determining the tariff under the Act, shall not show undue preference to any consumer of electricity, but may differentiate according to the consumer's load factor, power factor, total consumption of energy during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required".

As mentioned earlier, the KSEB by the order state government had hiked tariff seven times during the period from 1997 to 2002. Tariff hike was implemented without looking into the rationale of cost of supply or cost to serve as applicable to different categories of consumers with different voltage levels of supply. The State Electricity Regulatory Commission was constituted in the State of Kerala in November 2002. Prior to that the KSEB by the order of the Government had hiked tariff in August 2001 (25 % of base energy charges) and October 2002 (50 ps. Per Unit). The State Commission was constituted after doing all the harm to the industrial consumers, especially to the single largest consumer INDAL, whose cost of power is a significant component in the total cost of production as shown in Figure 7.4.

Prior to the appointment of Kerala State Electricity Regulatory Commission, KSEB was authorised to set or hike consumer tariffs. In practice State Government approved the tariff hikes from time to time as per the proposal of KSEB, without seriously analysing the efficiency or costs of the board. KSEB was functioning as a vertically integrated public sector monopoly under the direct control of State

Government and the decisions on tariff setting, tariff hike, new investment in generation, transmission and distribution were mostly influenced by political pressure ignoring merit of the case. Figure No.7.5 shows the oppressive hike in tariff imposed upon EHT Industrial Electricity Consumers in the State including Indian Aluminium Company Limited by KSEB during the period from Jan 1997 to October 2002.

The focal point of this study is the variation in industrial electricity tariff and regulatory intervention in the state covering areas other than tariff determination also as deliberated in the next chapter. The regulatory intervention was started from November 2002 onwards by force of the ERC Act 1998. With the enactment of Electricity Act-2003 all other Acts of Indian Power Sector including ERC Act 1998 got repealed from the appointed date of new act (E-Act 2003) i.e. 10 June 2003.

In this context, it is appropriate to mention here that there was no hike in EHT Industrial tariff after constitution of KSERC in November 2002. In other words, the State Commission did not find any reason to hike tariff during the last 8 years or more despite the proposals made by KSEB many times. This is solely on account of the fact that Kerala State Regulatory Commission is meticulously following the regulations and procedures for tariff determination (Figure 5.1 – Stages in Tariff determination for an integrated utility (ie KSEB in Kerala)) and acting as an independent regulator on the basis of merit and rationality. The era of adhoc and arbitrary method of tariff hike with ulterior political considerations is now over.

It is a paradox that INDAL, the company, which paved the way for the development of Kerala's power sector in a big way, had to pay the price for such arbitrary and adhoc policies. But in the ultimate analysis we would find that winding up INDAL's smelter at Alupuram and similar power intensive industrial units would be a loss to the power sector in particular and economy in general.

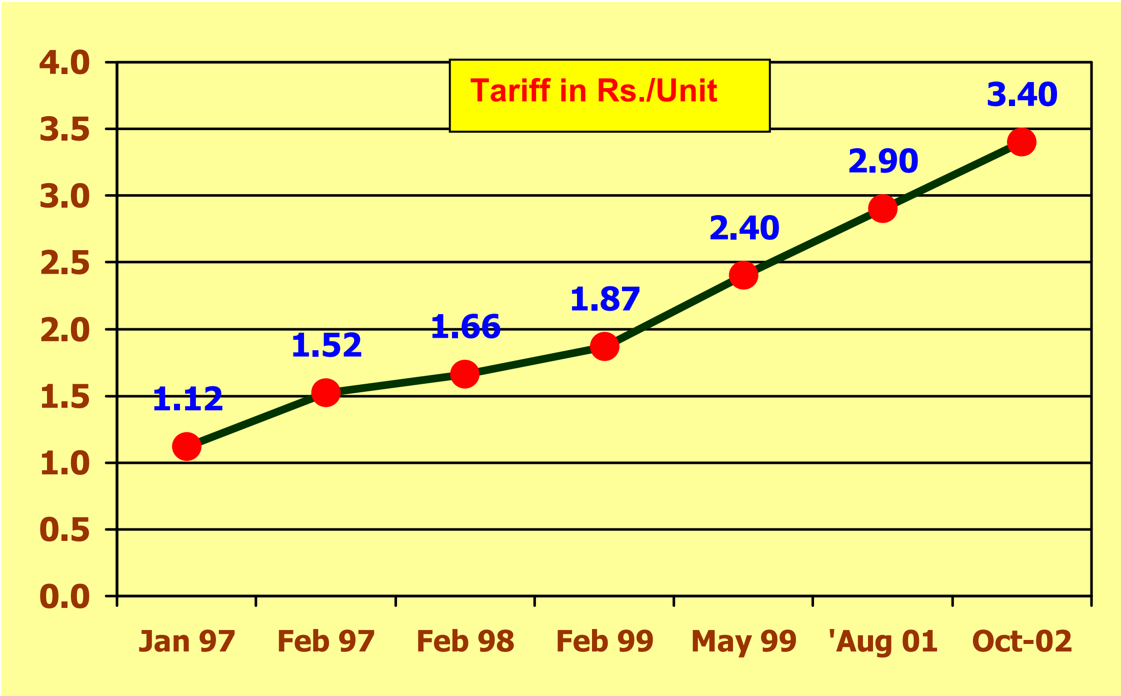
INDAL was the single largest consumer electricity in state with a contract demand of 50 MW till 1996 and the contract demand got reduced to 30 MW consequent to the closure of line-I pot room as stated earlier. Even after the closure of 20 MW connected load (Line-I pot room and its auxiliaries) INDAL stood first in the state in the areas of consumption of power and electricity bill payment. The following are the distinctive factors pertaining to INDAL, which differentiates a consumer as mentioned in section 29 (3) of ERC Act 1998.

1. INDAL was a bulk consumer of energy with a monthly consumption of more than 20 million units. Company was paying an electricity bill of Rs. 6.75 to 7 Crores per month.
2. INDAL was a steady consumer of power with a load factor above 95 % which was the highest achieved figure among similar industries in the state. Since INDAL's main raw material was electricity and electrochemical reduction of alumium was a continuous operation, uninterrupted supply of electricity was essential.
3. INDAL's power factor (PF) was almost unity which is in proof of energy efficient and operation and maintenance of load as well as electrical system
4. Since INDAL was paying monthly charges to the tune of 6.75 to 7 Crores against a single bill, KSEB's revenue collection expenditure was negligible compared to the situation when KSEB diverts the same quantum of power to LT users or other small industrial units.
5. During monsoon period, except Idukki and Sabarigiri reservoirs, all other storage dams start overflowing and the overflowing water wasted and ultimately reach Arabian Sea. This is due to insufficient storage capacity or reservoir capacity of Hydel projects. During such period of continuous rain, if a consumer like INDAL is present in the system KSEB would be able to generate income by making use of the opportunity.
6. Disappearance of major loads like alumium smelter would adversely affect grid the management of state grid.

The sole intention of reforms in electricity sector by the enactment of ERC Act 1998 or Electricity Act 2003 is to give due weightage to the factors mentioned above in a rational manner and thus evaluate the overall economic impact of exorbitant hike of electricity tariff as it would be permanent loss to the State's economy besides several socio-political issues.

Figure No. 7.5

Tariff hike imposed on EHT consumers during 1997-2002



Source: HT&EHT Industrial Electricity Consumers Association, Productivity Council,Kalamassery

7.5 Present status

Frustrated by the indifferent attitude of the KSEB and Government to consider the genuine demands of the company and its workforce, the company had to seek alternate source to procure electricity to maintain its smelting operations at Alupuram. Finding it impossible to continue the smelting operations using grid power, the Company approached the Power Trading Corporation of India Limited, a Central Government Undertaking (for short PTCIL) who offered to supply power at the interconnection point of Kerala grid with Southern Region Transmission System in the State of Kerala for Rs.2.50 paise per kWh. The Company had entered into an understanding with PTCIL who offered to supply 30 MW firm power at the rate of Rs.2.50 per kWh for a period up to 31 May 2004. Subsequently, the Company

Management approached the K.S.E Board for transmission of 30 MW of firm power (round the clock) to be delivered at the point of interconnection between Kerala Transmission System and Southern Region Transmission System. Representations made to the Government and Board were not fruitful and the KSEB wanted the Company to take up the matter before the Kerala State Electricity Regulatory Commission. The Kerala State Electricity Regulatory Commission had conducted a hearing on 2 September 2003 on Company's petition to wheel power from PTC. The KSERC allowed wheeling of 30 MW power from outside the state through PTC by a landmark order on 14 January 2004. (Annexure-IV, KSERC Order dated 14 January 2004)

The above order is regarded as the first of its kind in the whole country allowing open access (ie. Wheeling of power for the use of a consumer using KSEB's transmission lines) to a private company. The Board raised several objections against allowing wheeling to INDAL, but the Regulatory Commission has allowed open access to INDAL rejecting KSEB's arguments.

In section 3.1 (Findings of Commission) of the above order, the Commission Stated the following:

"3.1 - Indal has closed down the smelter plant with effect from 1.8.2003 and reduced its power intake from 30 MW to 5 MW. This development is a matter of serious concern to the Commission as the KSE Board has lost a major industrial consumer and it will further aggravate the already strained finances of the KSEB. The reduction in revenue collection by the KSEB on account of the closure of smelter plant is estimated to be around Rs. 5.5 Crores per month on an average. The average realization from Indal was Rs. 3.38 per kWh excluding electricity duty of Ps. 1/kWh and surcharge of Ps. 2.5 per kWh. The present level average realization by KSEB per kWh of energy sold is Rs. 2.96. Therefore the loss to KSEB due to the closure of Indal or grant of permission to Indal for availing power from PTC as requested in the petition of Indal would be Ps 42 per kWh of the energy consumption of the smelter plant. The KSEB has not indicated any

strategy to deal with the situation arising out of the closure of Indal, even though the Commission had made a specific reference to the Board in this regard"

In section 3.5.2 of the wheeling order, the Regulatory Commission has further stated the following:

"3.5.2 The Commission recognizes the fact that in deciding the various charges related to the import of 30 MW power by Indal, it has to strike a balance between two conflicting interests. Any adverse effect on the finances of the KSEB due to the transaction is detrimental to power development in the State. The continued closure of the smelter plant and the subsequent total closure of Indal would adversely affect the climate for industrial development with consequent setback to power development in the State. This is especially so, since the industrial consumption in the State is gradually coming down. The Commission firmly believes that it is impossible to sustain power development without industrial development"

It is clear from the above observations of the Regulatory Commission that KSEB was not serious about the impact of closure of INDAL - one of the major industrial consumers in the State - and the Board has not framed any strategy to deal with the adverse impact on industrial power consumption in the state consequent to the closure of INDAL's smelter.

Unfortunately, Company could not avail PTC power due to the fact that PTC had expressed their inability to supply power @ Rs 2.50 per unit as promised earlier due to the grim power situation in southern states caused mainly due to declaration of free power for agricultural sector by states like Andhra Pradesh and Tamil Nadu.

As mentioned earlier, after the de-energisation of Smelter on 1 August 2003, the company rendered the surplus 343 permanent employees on 'stay home' paying full salary, annual bonus and all other benefits including medical reimbursements. The Government of Kerala constituted a high level committee called 'Hindalco Committee' comprising of Ministers of Industries and Labour, Chairman KSEB, Principal Secretaries of Power and Industries, Labour Commissioner, Trade Union and political leaders and representatives of Company Management. After several deliberations, the Hindalco committee concluded in the month of May 2008 that re-energisation of Alupuram smelter would not be feasible as there is no grid power available at economically viable rates either from within the state or from outside the state through wheeling at rates affordable for smelting operations. Hence the committee requested management to submit alternatives. The company management proposed expansion of extrusion plant by adding one more extrusion press and thereby increase extrusion production from the present level of 1000 TPM to 2000 TPM. The casting plant, which supplies aluminium billets to extrusion plant, also will be augmented to gear up increase in billet production. A conciliation agreement to this effect was executed between Management and Trade Unions in the presence of Labour Commissioner on 30 May 2008. However, due to the long pending issues with KSEB and Government, the implementation of the above mentioned agreement was done only on 1 June 2009. Even though the original number of permanent workmen rendered surplus and put on stay home with full wages and other benefits on 1 August 2003 was 343, due to retirement and optional VRS, the number has come down nearly 200. As per the terms of the conciliation agreement executed on 30 May 2008, company has created a reserve pool of 85 workmen under 'stay home' (with wages and other benefits) for the proposed expansion of extrusion plant and remaining people opted for voluntary retirement.

The company is in the process of inviting bids for the proposed expansion of extrusion business at Alupuram, but a final decision to commence the project would be taken after evaluating the market conditions so that the new capital investment should not affect the overall viability of the present business.

7.6 Socio-economic impact of closure of smelter consequent to tariff hike

When INDAL's Alupuram Smelter was working in full swing and manufacturing primary alumium smelter in its full capacity of 21500 TPA, the total contract demand was nearly 50 MW and monthly consumption of electricity was 30 million units. The contract demand was reduced to nearly 30 MW after the closure of Line-I (25 kA) pot room in the year 1996. The remaining smelter production capacity of 14000 TPA from Line-II pot room was also stopped on 1 August 2003 consequent to the tariff increase affected by KSEB in the month of October 2002. After the closure of Line-II pot room, the contract demand of electricity has been reduced to 5 MW. The monthly electricity bill prior to closure was 6.75 to 7 Crores which amounts to Rs 80 Crores annually. Since company's monthly consumption of power at the time closure of Line-II pot room was nearly 20 million units per month, a roll back in tariff at the rate of 50 ps./ Unit would have ensured the survival of Line-II smelter. By doing so, the KSEB would sacrifice Rs. 1 crore per month, ie. 20 Million Units x Rs.0.50 / Unit = Rs 10 Million (1 Crore).

Let us look into the overall loss to the State's economy on account of closure of Line-II smelter of M/s Indian Alumium Company on 1 August 2003.

Table No. 7.1

Contributions by INDAL's Smelter

Items	**Amount per Year (in Rs. Crores)**
Electricity Charges	80
Taxes, Duty etc. to Government	18
Purchases from within the State	6
Employment (Wages, salaries etc)	16
Service Contract Jobs within the State	4
Transportation Charges	6
Total	130
When INDAL paid Rs. 80 Crores as Electricity Charges, Rs.50 Crores spent for services and for tax, duty etc. within the state annually.	

Source: Annual report of INDAL for the year 2002-03

From the table No.7.1 it can be seen that INDAL was contributing to the Government exchequer Rs. 18 Crores per annum by way of taxes and duties. In addition to that, Government is also benefited by at least a portion other payments made to employees, suppliers, service contractors, transporting companies etc by way of downstream economic activities. The amount disbursed to the above groups will automatically trickle down to the various sections of the society. When INDAL was working in full swing the total strength of permanent workmen was 1091, which has now come down to 350 on account of closure of two major plants (Line-I and Line-II pot rooms). The total number of staff members has come down during the said period from 300 to 75. Similarly the total number of casual, temporary and contract workmen has also reduced from 200 to 50. There is a substantial reduction in number of indirect employment also which is not quantified here.

If we go by the merit and rationale of overall impact to the State economy, we can infer that, if the Government and KSEB had allowed a roll-back in tariff to the tune of 50 ps./Unit as requested by the company (which is equivalent to Rs. 1 Crore per month), the closure of smelter could have been avoided. By doing so, the direct revenue loss to the KSEB would be Rs. 12 per annum (without looking at the benefits to the KSEB in retaining a bulk consumer like INDAL within its grip as mentioned in section 7.4), but the Government could have saved Rs 18 Crores to the exchequer in terms of taxes and duties. In addition to above all, by avoiding closure, the plight of the affected stakeholders like employees (who lost the job), suppliers (who lost orders), transporters (who lost transport contract), service contractors (who lost service jobs), contract workmen (who lost job) and other indirectly employed workmen could have been avoided.

As per the Government Order (G.O.(Rt) No. 163/03/03/PD), the relief was granted to INDAL for a period of three months (Refer Annexure – II) after detailed consideration by the Government in view of the probable plight of employees and workforce in case company shuts down its smelting operations. That means, Government got convinced that relief in tariff was essential to sustain operations. But there was no Government will to extend the relief, which was granted on the basis of merit, for further periods. Even after agreeing in principle that there is a potential threat on the future of employees and workforce and the management is left with no option other than closing down smelter, there was no concerted move by the Government or KSEB to extend relief or to allow tariff incentives or roll-back in tariff to make the operation of smelter economically viable and thereby ensure its survival.

After the permanent closure of smelters, INDAL (Hindalco) disposed off most of the equipment and facilities of pot rooms including electrolytic reduction cells. In this context, it is worth mentioning here that, as per the present capital investment norms, the amount required to set up such a new smelting facility would be approximately 450 to 500 Crores including new power plant.

7.7 Conclusion

This case study on INDAL is classical example to demonstrate the illogical, adhoc and arbitrary decisions taken by the Board during the pre-regulatory period. During that period, there was no mechanism in place with the decision makers in the Government and bureaucracy to study the impact of such hike in tariff on the industries and society in general and state's economy in particular. No system was there with the Government to assess the direct and indirect losses likely to be suffered on account of sudden closure of a factory due to oppressive hike in tariff. No study was conducted by KSEB prior to tariff hikes to assess the potential losses in various areas like revenue earnings, opportunity loss, load management issues etc in the event of closure of a major consumer like Indian Alumium Company Limited. It is imperative to note that no tariff hike was imposed upon EHT Industrial consumers till date right from the inception of Kerala State Electricity Regulatory Commission in November 2002. That means there was no hike for the last 8 and more years. The tariff of EHT Industrial consumers revised by KSEB is still in force. The KSERC has allowed power factor incentive and rationalized ToD tariff in between and which in turn has resulted in marginal reduction of EHT tariff. This is more than sufficient to prove that the hike in tariff imposed upon HT/EHT consumers during the period from January 97 to October 2002 was oppressive and arbitrary.

It can be concluded that, the closure of Indian Alumium Company Limited, Alupuram Smelter (INDAL – Presently known as Hindalco Industries Limited) is a permanent loss to the industrial, power and socioeconomic sectors of Kerala State.

CHAPTER – 8

THE IMPACT OF REGULATORY REGIME IN KERALA: AN ANALYSIS

8.1 Introduction

The Kerala State Electricity Regulatory Commission (KSERC) was constituted under the provisions of Subsection (1) of Section 17 of the Electricity Regulatory Commissions Act, 1998. With effect from 10th June, 2003, the Commission has come under the purview of the Electricity Act, 2003, as the Electricity Regulatory Commissions Act, 1998 has since been repealed. The Commission was constituted *vide* Government of Kerala Order (Ms) No.34/2002/PD dated 14 November, 2002 notified in the Govt. of Kerala Gazette, Extra Ordinary dated 18 November, 2002. The Kerala State Electricity Regulatory Commission is a body corporate having perpetual succession and a common seal, with power to acquire, hold and dispose of property, both movable and immovable, and to contract and shall, by the said name, sue or be sued. In addition, the Commission is a quasi-judicial body. With effect from 10 June, 2003, the Commission has come under the purview of the Electricity Act, 2003, as the Electricity Regulatory Commissions Act, 1998 has since been repealed.

The Commission consists of Chairman and two Members. In recognition of the need for multi-disciplinary approach while addressing issues related to independent regulation, the statute prescribes that the Chairman and Members shall be persons of ability, integrity and standing who have adequate knowledge of, and having shown capacity in, dealing with problems relating to engineering, finance, commerce, economics, law or management. The Chairman and Members are appointed by the Government of Kerala on the recommendation of a selection committee constituted by the State Government as prescribed under the statute. The statute also provides for the appointment of a Secretary, functioning under the Commission, whose powers and duties are defined by the Commission.

In this chapter, an attempt is made to analyse the impact of electricity regulatory regime in Kerala in areas like ARR approval, industrial tariff, financial performance of KSEB, T&D loss, Scheduling and generation, power purchase etc. The compliance of KSEB and KSERC in meeting the key provisions of Electricity Act 2003, National Power Policy and National Tariff Policy in meeting the requirements of Industrial Consumers in the State of Kerala also will be studied. The period of study in this chapter is from the inception of KSERC in 2002 to 2010. We can find from following sections that the KSERC has shown at maximum prudence in the analysis of KSEB's tariff petitions and has questioned the merit of each and every demands put forward by the Board. The analysis of ARR & ERC by KSERC for the year 2010-11 has been taken as a typical case for analysis and at the same the regulatory intervention by the Commission for the period from 2002 to 2010 is also analysed.

8.2 Summary of ARR&ERC approvals done by the Commission

The Kerala State Electricity Board (*hereinafter referred to as KSEB or the Board*) in accordance with the KSERC (Tariff) Regulations 2003, filed the Aggregate Revenue Requirements (ARR) and the Expected Revenue from Charges (ERC) for FY 2010-11 before the Commission on 24-12-2009. Prior to filing of the petition, the Board had sought extension of time for filing the petition till 31-12-2009, and the Commission after considering the request had allowed time till 24-12-2009. In the petition the Board has proposed a record revenue gap of Rs.2219.60 crore and no proposal was made for bridging such a large revenue gap. The Commission directed the Board to file the proposal for bridging the revenue gap and the Board expressed reluctance raising certain reasons. Therefore the Commission admitted the petition on 15-1-2010 to avoid further delay. The Commission so far has issued six Orders on ARR & ERC of the Board starting from 2003-04 as shown below (Table8.1)

Table 8.1

Details of ARR & ERC approved by KSERC

Year	Date of submission of ARR&ERC	Revenue Gap proposed by KSEB (Rs. Crore)	Approved ARR (Rs. Crore)	Approved Revenue (Rs. Crore)	Approved revenue (gap) /surplus (Rs. Crore)	Date of order
2003-04	1-8-2003	926.08	**3,697.37**	**3,141.37**	**(556.00)**	31-12-2003
2004-05	15-12-2003	854.19	**3,492.46**	**3,196.00**	**(296.46)**	16-4-3004
2005-06	15-11-2004	492.25	**3,367.32**	**3,316.01**	**(51.31)**	23-3-2005
2006-07	30-11-2005	302.78	**3,680.43**	**3,865.05**	**184.62**	30-3-2006
2007-08	11-12-2006	430.11	**4,074.22**	**4,403.95**	**329.73**	26-12-2007
2008-09	21-12-2007	754.69	**4,983.27**	**4,979.34**	**(3.93)**	19-4-2008
2009-10	29-12-2008	1,099.28	**5,316.30**	**4,981.00**	**(335.30)**	17-4-2009

Source: Kerala State Electricity Regulatory Commission

The revenue gap of Rs. 556.46 crore for the year 2003-04 arrived at by the Commission was recommended to be bridged by way of exemption from payment of Electricity duty amounting to Rs.182.56 Crore and by availing a subsidy of Rs. 375 Crore from Government. The revenue gap for the year 2004-05 was to be filled up by exemption from paying electricity duty under Section 3(1) and Section 4 of Kerala Electricity Duty Act, 1963 to the tune of Rs.200 Crore and by providing the balance amount of Rs.96 Crore by way of revenue subsidy by Government.

The truing up petition for 2003-04 & 2004-05 filed by the Board was disposed of together by the Commission by allowing an amount of Rs.360.06 Crore. This was adjusted against the revenue surplus of Rs. 329.73 Crores arrived at in the ARR&ERC for 2007-08 resulting in a net deficit of Rs.30.34 Crore for 2007-08. Based on the petition filed by the Board for revision of tariff, the Commission in the order dated 26-11-2007 revised the tariffs with effect from 1-12-2007. The increase in revenue due to tariff revision was estimated as Rs.69.79 Crore for a full year and Rs.23.26 Crore for the balance four months of 2007-08.

Against the revenue surplus of Rs.184.64 crore fixed in 2006-07, the Commission directed the Board to file tariff revision proposal, however, the Board did not file the same. The Commission finalized truing up for the year 2005-06 by approving the revenue surplus of Rs.181.36 crore, which was adjusted against the revenue gap of Rs.335.30 crore approved for the year 2009-10. The Commission directed the Board to file appropriate proposals for tariff rationalization for 2009-10 and accordingly KSEB filed a tariff petition on 24-07-2009, for additional revenue of Rs.150.86 crore on a yearly basis. Other major highlights of the proposal were (a) introduction of non-telescopic tariff for domestic consumers, (b) 15% & 20% increase in demand and energy charges respectively for HT Commercial class, (c) 25% increase in tariff for Bulk supply (BST) to Licensees and (d) reduction to the tune of 10% of the tariff applicable to Kerala Water Authority (KWA). KSEB also proposed to rationalize the ToD tariff applicable to HT/EHT consumers and proposed a new ToD tariff for LT industrial consumers. The Commission in its order dated 2-12-2009 rejected the proposal on rationalization/revision of tariff proposed by KSEB for LT-I A(Domestic) and HT-IV (Commercial) since the proposals were against the provisions of the Act and would entail a tariff shock for certain group of consumers. Besides the Commission noticed that after the completion of pending truing up proposals from 2006-07 onwards, the picture of deficit might change. The Commission deferred the proposal on Bulk Supply Tariff to licensees. The Commission revised the Time of Day Tariff for HT-EHT consumers to be effective from 1-1-2010. Maximum demand based tariff was introduced for LT Industrial and LT VII (A) & (C) consumers having connected load of 20 kW and above as an optional scheme. With a view to staggering the peak time load demand, an optional Time of Day tariff was also introduced for LT Industrial consumers who have opted for a maximum demand based tariff and having 30 kVA contract demand or above.

8.2.1 Procedural Overview

In the ARR for FY 2010-11, the Board has projected a revenue requirement of Rs.7503.98 Crores and a revenue receipt of Rs. 5284.38 Crores thereby leaving a revenue gap of Rs.2219.60 Crores. Since such a gap would entail increase in existing tariff by about 46%, before admitting the petition, the Commission vide letter dated 2-1-2010 directed the Board to provide a detailed proposal on bridging the revenue gap. The Commission also directed the Board to ascertain from the Government whether subsidy if any is intended by the Government to avoid a steep tariff increase. The Board in its reply stated that, filing a proposal on the revenue gap projected by Board would be a futile exercise since in the past, the Commission had substantially reduced the ARR proposed by the Board. Hence, appropriate measures like filing tariff petition or seeking subsidy from the Government or to keep the revenue gap, as regulatory asset will be taken once the Commission approves the ARR&ERC. The Board also informed that, they had requested the Government to communicate the decision, if any, on the provision of subsidy to the consumers. In the letter dated 29-1-2010, the Board further attempted to appraise the Commission on the issues on revenue gap. According to the Board, the accounts of the Board are still being prepared under Electricity (Supply) Annual Accounts Rules (ESAAR) - 1985 which are being audited by C&AG. The actual revenue gap for various years has been substantially higher than what has been approved by the Commission. It would be difficult for the Board as a distribution licensee, to limit expenses especially for power purchase cost. The Board further stated that it cannot propose on its own tariff proposals under the provisions of the Act and conceded that they did not possess necessary expertise to conduct studies on T&D loss reduction, improving efficiency of generating stations, man power utilisation etc., as directed by the Commission.

Before taking up the ARR&ERC for 2010-11, the Commission expressed its views on the reply given by the Board, which were communicated to the Board vide letter dated 15-1-2010. The Commission was not in agreement with the contentions of the Board on major issues such as proposal on bridging revenue gap and various directions issued to the Board. According to the Commission, KSEB is a responsible public entity entrusted with the task of providing electricity at a reasonable cost to the public. The Government at all levels is taking maximum effort to keep the entity under public ownership. The Board has inherent obligation and duty to optimally plan, develop and maintain the electricity system, and is expected to exercise such functions in the most reasonable and efficient manner. KSEB has been consistently projecting expenses more than what is optimally required for efficient service. Such projections are placed before the public, without serious concern on its impact, thereby revealing an unwholesome aspect of cost plus regime. In the absence of proper and reliable estimates from KSEB, the Commission in the past was forced to exercise its regulatory scrutiny to optimize, control and prune certain expenses. The Commission was of the firm view that it was not bound to accept all the projections of the Board without scrutiny. It was not the intention of the regulatory scrutiny to scale down the expenses, which were over projected by the licensee (KSEB). In actual terms, KSEB has failed to control the expenses at the approved level, notably in areas where restraints have to be observed such as many items of revenue expenditure, and reduced the expenditure much below the desired level in areas where it was very much needed such as capital expenditure. Even after seven years of regulatory regime in the State, the Commission has received no material on record to establish that a professional body like KSEB has an internal mechanism to limit the various expenses at the approved level and implement the capital programmes as proposed. The Commission opined that, such an approach of the licensee (KSEB) in not having a system or initiative to optimize the operations may render the regulatory regime less effective in the State.

The Commission insisted on proposals for filling up the revenue gap of Rs.2219.60 Crore as projected by the Board mainly on the reason that KSEB should visualize and gauge the impact of such a huge revenue gap on 97 lakh consumers in the State. According to the Commission, if KSEB proposes such a huge revenue gap, it cannot shy away from its responsibility of proposing the means to bridge the revenue shortfall through tariff revision or efficiency improvement or direct subsidy from the government or a combination of all of these. As per the ARR&ERC for

2010-11 projected by the Board, the average cost of supply was estimated to Rs.5.06/kWh (Rupees five and paise six), which was much higher than the levels existing elsewhere. KSERC in principle disagreed with KSEB's practice to project such a high level of expenditure, without proposals or attempts to plan and control the expenses saying that Cost plus regulatory regime is not about passing on all costs incurred by the utilities, but about prudently optimal and efficiently managed costs being loaded on to the consumers.

Regarding the lack of expertise for the conduct of various studies, the argument of the Board was surprising. If in a particular domain, expertise was not available, either the expertise should be acquired or outsourcing to be resorted to. Commission opined that the Board is not the only one electric utility in India and is not required to reinvent the wheel. It can emulate the best practices adopted elsewhere in the Country. There are several success stories reported on the achievements in the power sector in India especially under public management. Further, there is no dearth of expertise in the country. Already M/s. PFC Consulting and others are helping the Board on re-organisation. In the past also Board has benefited from the services of consultants. It was surprising to note that it took nearly seven years since the directions have been issued, to understand its own the limitations. Commission observed that the Board has to realize the cost of time and should speed up the efforts. The Commission after considering all these aspects and also the fact that the ARR&ERC for the year 2010-11 was delayed, decided to admit the petition on 15-1-2010.

After admitting the petition, the Commission sought clarifications on various issues on the petition from the Board vide letter dated 15-1-2010. The Board provided its reply on 5-3-2010 after some delay. The Commission directed the Board to publish the summary of the petition by giving time till 1-3-2010 for providing comments by the Public and stakeholders. The Board published the summary of the petition in the leading dailies.

In the meanwhile, the Commission vide letter dated 10-1-2010 directed the Board to submit truing up petitions for the years from 2006-07 to 2008-09. On the request of the Board the Commission allowed time till 20-1-2010 for filing the Truing up petition for 2006-07 and for other years till 31-1-2010. Further extension of time was also given. As on date of this order, the petition for 2007-08 and 2008-09 were not yet filed. In its absence, the Commission could not take a considered view on the exact position of revenue gap/surplus for the years till 2008-09. Hence Commission ordered that the present order on ARR&ERC 2010-11 will be subjected to the outcome of truing up exercise for the years 2006-07 to 2008-09.

8.3 Review of Capital Expenditure

8.3.1 Introduction

The Board has initiated a new interactive approach for identifying capital projects in generation, transmission and distribution since 2008-09. Probable load growth was projected based on the feedback received from stakeholders and in consultation with elected people's representatives certain projects were formulated. An ambitious plan of capital expenditure for Rs.1377.70 Crores proposed in 2009-10 was revised by the Board to Rs.947.66 Crore. For the year 2010-11, capital expenditure of Rs.995.15 Crores was proposed.

The capital expenditure for generation in 2009-10 and 2010-11 includes 9 ongoing projects viz., Kuttiyadi tail race, Kuttiyadi additional extension, Pallivasal extension, Kuttiar diversion, Ranni-Perunad SHP, Thottiyar, Sengulam Augmentation, Adyanpara SHP, and Poozhithodu SHP, with a total out lay for the year 2009-10 and 2010-11 as Rs.113.70 Crore and Rs.124.26 crore respectively. Out of the 6 tendered projects, 3 projects were under pre-qualification stage and two other projects were already tendered. One project (Athirappally) was held up. The total out lay for tendered projects for 2010-11 was Rs.22.65 crore.

In 2009-10, 8 projects were taken up for tendering which were in various stages for which Rs.19.74 crore was earmarked for 2010-11. Another 14 projects were prioritized for approval (total 207MW to generate 592.02MU) during the year 2010-11 and 2011-12. Other capital works in generation include, capital works for diesel projects BDPP/KDPP, renovation and modernization of hydro stations, survey and investigation, revamping seismic network in Idukki region, mechanical fabrication, civil R&D, construction of administrative complexes, and Dam safety works etc., the total outlay for these works was Rs.284.34 crore.

In transmission, the projects planned for 2010-11 are 2 nos. of 220kV substations, 19 nos. of 110kV substations, 6 nos. of 66kV substations and 19nos of 33 kV substations. Further 28.5 km of 220 kV lines, 138.8 km of 110 kV lines, 13.5 km of 66 kV lines and 138 km of 33 kV lines were also planned. In the petition, the Board has committed that the financial viability of these projects will be submitted by January 2010. Modernisation of Load Dispatch centre was another project included as part of transmission.

In the distribution wing, Board was planning to provide 5 lakh connections and to construct 3000 km of 11kV lines, 3800km of LT lines and installation of 5000 distribution transformers. 8 lakh faulty meters were also proposed for replacement in 2010-11.

The Board reported that APDRP scheme sanctioned by Government of India for Rs.853.62 crore included 3 circle schemes (Rs.148.24 crore), 46 nos. of town schemes (Rs.341.87 Crore) and 3 nos. of sub-transmission and distribution project for cities (Rs.373.56 crore). These projects were either completed or short closed on 31-3-2009. The total allowable expenditure under APDRP is Rs.556.60 Crore. For the completed schemes 25% of the amount will be provided as grant. The city scheme (Thiruvananthapuram, Ernakulam and Kozhikode) envisages laying of 11kV UG cables and installation of RMUs, compact secondary substations and transformers. The expenditure up to 31-3-2009 under the city scheme was Rs.82.19 crore. Balance work under the project was planned to be completed using Board’s own funds.

The Board obtained sanction for implementing RAPDRP scheme during 11th five-year plan from Government of India. The project is proposed to be implemented in 43 towns. Part A of the project consists of establishment of IT infrastructure and part B consists of distribution infrastructure. As part of Part A, project worth Rs.288.33 crore was forwarded and Rs.241.39 crore is expected from the Government of India and balance Rs.76.04 crore to be met from Own fund. If the project is implemented in time, the complete funding under Part A will be converted as grant.

As part of RGGVY projects for all districts are under preparation. Revised DPRs for southern districts such as Thiruvananthapuram, Kollam, Pathanamthitta, Alappuzha, Kottayam, Ernakulam and Thrissur are being submitted for REC approval.

8. **3.2 Analysis**

The KSERC in the previous Orders had mentioned the lack of progress in capital expenditure programmes. The Board has been submitting the investment proposal as part of the annual budget, without providing the scheme-wise details or viability studies. The information provided by the Board even after several queries was incomplete and hence which was not useful for continuous monitoring of the projects. Hence, project monitoring and evaluation could not be taken up effectively. The Commission on several occasions had made it clear that for the approval of the investment plan, project-wise details with necessary information on the viability of the project need to be submitted. In the ARR petition, the Board stated that scheme-wise details with DPR would be submitted by February 2010 and Chief Engineer Planning was entrusted with the task. However, the information was provided by the Board only on 24-4-2010, which KSERC could not be evaluated.

The KSERC noted that the Board was following a strategy of projecting the capital expenditure initially high, which was later scaled down successively. The Board has proposed Rs.1022.38 Crore in the ARR for 2007-08, which was revised to Rs.956.17 Crore subsequently. Similarly, for the year 2008-09, Rs.1145 Crore was proposed which was revised to Rs.1047.6 Crore. For 2009-10 the capital expenditure proposed was Rs.1377.10 crore which was about 31% more than the revised estimates for 2008-09. However, it was substantially scaled down to Rs.947.66 crore later i.e., the projected capital expenditure in the ARR later revised downwards and as per the actuals, the performance was much lower as shown below (Table-8.2).

Table No. 8.2

Performance under capital expenditure 2006/07 to 2009-10

Year		Generation	Transmission	Distribution	Other works	Total
2006-07	**Proposed**	**250.00**	**218.50**	**290.00**	**1.50**	**760.00**
	Revised	323.94	168.78	288.00	1.50	782.22
	Actuals	**150.77**	**139.49**	**255.01**		**545.27**
2007-08	Proposed	336.22	221.80	464.36		1,022.38
	Revised	344.53	221.50	386.09	4.05	956.17
	Actuals	**115.60**	**241.34**	**284.43**		**641.37**
2008-09	Proposed	540.52	181.00	419.52	5.05	1,146.09
	Revised	310.37	276.88	456.25	4.10	1,047.60
	Actuals	**68.89**	**153.30**	**223.16**		**445.35**
2009-10	Proposed	403.33	366.73	600.64	6.40	1,377.10
	Revised	262.82	240.66	436.40	7.78	947.66
2010-11	**Proposed**	**284.34**	**275.97**	**425.00**	**9.84**	**995.15**

Source: Kerala State Electricity Regulatory Commission

The jacking up of figures in the ARR may be for enhancing the interest liability and also depreciation benefits for the period under scrutiny. Hence, the Commission would seriously consider to claw back the excess interest and depreciation on account of actual lower performance. Based on the information provided by the Board over the years, the physical progress in the generation sector is analysed below (Table 8.3):

Table No. 8.3

Status of Ongoing Projects

	Capacity	**Target date**		
Hydel schemes		**As per Five year plan**	**As per 2008/09 ARR**	**As per 2009-10 ARR**
Kuttiyadi tail race	3.75MW	2007-08	Nov.2008	Commissioned 1st unit on 9-11-2008 and 22-10-09
Neriamangalam Extn	25MW	2007-08	May-08	22-5-2008
Kuttiyadi Addl Extn	100 MW	2007-08	May-09	Mar-10
Azhutha Diversion	57MU	2006-07	Apr-07	May 2007
Kuttiyar Diversion	37MU	2007-08	Jun-07	Jun-09

Source: Kerala State Electricity Regulatory Commission

All the on going projects are delayed beyond the initial target dates. As per the information available, 3 projects have been completed now. The cost due to delay in commissioning the projects is the additional cost of power purchase necessitated, which needs to be imposed on the Board as penalty. The Commission will be addressing this issue separately.

The Commission's observation on Baitarni Coal block and the proposed Cheemeni Power project was that without even a prefeasibility report, no evaluation of the project would be possible.

The achievements in transmission and distribution sector were very low as per the five-year plan targets as shown below (Table No.8.4):

Table No. 8.4
Physical target and Achievement in Transmission capital expenditure

Substations	Transmission	2007-08	2008-09	2009-10	2010-11	2011-12	Total
As per Five year plan Proposal	220kV	2	0	1	2	1	6
	110kV	11	11	8	6	18	54
	66kV	1	4	0	0	1	6
	33kV	12	26	7	4	7	56
Actual Achievement reported	220kV	1	-	-	-	-	1
	110kV	4	2	-	-	-	6
	66kV	1		-	-	-	1
	33kV	13	16	-	-	-	29
Lines Ckt kms	Transmission	2007-08	2008-09	2009-10	2010-11	2011-12	Total
As per Five year plan Proposal	220kV	39.34	18.61	28.5	15	17	118.45
	110kV	124	134.8	41.8	85.58	286.4	672.58
	66kV	40	14.61	164	57.6	0	276.21
	33kV	174.63	309	63.94	63.94	10	621.51
Actual Achievement reported	220kV	1.01	-	-	-	-	1.01
	110kV	56.38	17.5	-	-	-	73.88
	66kV	11.13	-	-	-	-	11.13
	33kV	105.27	169.27	-	-	-	274.54
Distribution	Transmission	2007-08	2008-09	2009-10	2010-11	2011-12	Total
As per Five year plan Proposal	11kV lines (Ckt kms)	3427	3177	3225	3264	3463	16556
	LT lines (Ckt kms)	4043	3798	3663	4186	3575	19265
	Distribution transformers (Nos)	2009	2286	2346	2503	2646	11790
Actual Achievement reported	11kV lines (Ckt kms)	1807	3018	-	-	-	4825
	LT lines (Ckt kms)	8128	7636	-	-	-	15764
	Distribution transformers (Nos)	2553	4109	-	-	-	6662

Source: Kerala State Electricity Regulatory Commission

The Commission sought details of load flow studies to support the transmission plan. The Board stated that the studies were not conducted on regular basis but for annual peak only due to inaccurate metering and lack of details. There was no doubt that in the absence of systematic load flow studies, the constraints and stability of the system cannot be predicted. Commission observed that the reasons stated by the Board that meters are inaccurate and details on load flow are insufficient are illogical. Thus, the reply from Board clearly indicates that transmission planning in KSEB is weak and it needs to be strengthened urgently.

The Board stated that region-wise voltage adalaths were conducted and results were provided. It is apparent that the efforts made were not scientific and no integration was made into the overall planning process.

The Commission observed that under Modernisation of Load Dispatch Centre, the Board has been continuously providing a budget provision, but no work has been executed so far. It was noted that in 2008-09 Rs.153 lakh & in 2009-10 Rs.266 lakhs were provided. In 2010-11, Rs.5.97 Crore was earmarked for this. On this issue, Board’s reply is that modernization of LD is under the consideration of the Board and would be reported after finalisation. This shows that even without a firm project, KSEB is making provisions as part of the proposed capital expenditure.

The Commission has analysed the capital expenditure proposed by the Board in the ARR and the actual expenditure and the deviations. The following table gives the details (table 8.5).

Table 8.5

Capital expenditure proposed in ARR and actual (2002-03 to 2009-10)

Proposed in the ARR		**Rs. Crore**						
		2003-04	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**
Capital Expenditure		453.40	459.01	695.21	662.60	924.49	1061.15	1293.00
IDC capitalized		115.45	115.73	99.51	53.30	37.11	25.75	27.87
Other expenses capitalized		119.25	123.53	158.95	43.90	65.26	59.19	55.82
Total capital expenses		**688.10**	**698.27**	**953.67**	**759.80**	**1026.86**	**1146.09**	**1376.69**
Expenses transferred to Gross asset		924.65	707.84	905.68	603.33	821.48	912.07	1189.26
Actuals	**Rs. Crore**							
	2002-03	**2003-04**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	
Capital Expenditure	235.36	621.93	357.00	407.82	459.13	296.30	551.73	
IDC capitalized	101.08	78.11	62.04	48.50	35.13	29.33	22.71	
Other expenses capitalized	118.15	109.05	42.88	43.61	43.19	48.08	70.75	
Total capital expenses	454.59	809.09	461.92	499.93	537.45	373.71	645.19	
Expenses transferred to Gross asset	801.37	968.51	501.42	651.65	505.23	467.70	564.56	
Difference	**Rs. Crore**							
	2002-03	**2003-04**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	
Capital Expenditure		168.53	-102.01	-287.39	-203.47	-628.19	-509.42	
Total capital expenditure		120.99	-236.35	-453.74	-222.35	-653.15	-500.90	
Expenses transferred to Gross asset		43.86	-206.42	-254.03	-98.10	-353.78	-347.51	

Source: Kerala State Electricity Regulatory Commission

As noted above, the achievement in terms of completion of projects was much lower than projected. Considering this, the Commission directed the KSEB that scheme/project wise details with benefits quantified, date of commencement, physical and financial progress, target date of completion etc., are to be submitted along with ARR&ERC. KSERC has made it clear that in the absence of above details, the Commission may be forced to disallow interest commitments in the tariff.

8.4 Sales Energy Projections

8.4.1. Sales projections

The Board has projected the energy sales for the year 2010-11 based on the past trend. According to the Board, energy sales in the State was showing an increasing trend since 2003-04. The Board stated that, as in the previous years, the energy consumption was estimated by considering factors such as connected load, actual growth of consumers, regional characteristics, seasonal variations, change in consumer habits etc. According to the Board, the methodology used in the past was realistic and the percentage error was less than 2%. However the methodology used in the previous years required modification due to the power restrictions in 2008-09 (on account of low monsoon and precarious water levels in dams). Energy sales in 2008-09 was lower on account of power restrictions such as half an hour load shedding, 20% restriction in consumption for HT-EHT and LT consumers and high rate for consumption above 200 units per month for domestic consumers. These restrictions were removed on 1st May 2009. In view of the distortion in sales data, the Board omitted the energy sales for 2008-09 for projecting the sales for 2010-11.

Energy sales for 2009-10 was projected as 13679 MU by KSEB, which was later re-estimated as 13870MU, due to lifting of restrictions. KSEB has expected an addition of 5.13 lakh consumers in 2009-10. The average growth of sales for the period from 2003-04 to 2008-09 was 6.9% of which LT growth was 8.4% and HT growth was 3.5%. Compared to this, in 2008-09, the growth rate was only 3% and for many consumer categories (agriculture, HT-EHT, licensees) sales growth was negative on account of restrictions.

By excluding the sales for the year 2008-09, sales for 2010-11 was estimated effectively by considering sales from 2003-04 to 2007-08. KSEB has taken into consideration, an addition of about 5 lakh consumers in 2010-11. Accordingly, the total sales projected for the year 2010-11 is 14830 MU as shown below (Table 8.6).

Table 8.6
Estimated Energy Sales by KSEB

	Actual						Revised estimate	Projections
Category	**2003-04**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**
LT Category								
Domestic	4004	4262	4668	5213	5603	5931	6580	7078
Commercial	879	948	1093	1246	1378	1502	1706	1886
Industrial	751	783	874	934	984	1015	1131	1211
Agricultural	202	191	190	220	231	225	238	250
Street Lights	166	183	208	229	249	294	305	325
Sub total LT	**6002**	**6367**	**7033**	**7842**	**8445**	**8967**	**9960**	**10750**

HT category								
HT – I	1125	1238	1362	1436	1461	1326	1439	1485
HT – II	130	141	130	135	138	107	115	119
HT – III	9	9	10	9	9	9	10	10
H – IV	304	339	378	431	507	579	686	723
EHT 66/110	1107	1036	1004	1070	1024	966	1105	1158
Railway Traction	46	44	58	72	109	142	161	168
Bulk Supply	188	212	296	335	357	317	394	417
Sub total HT	**2909**	**3019**	**3238**	**3488**	**3605**	**3446**	**3910**	**4080**
Total	**8911**	**9386**	**10271**	**11330**	**12050**	**12413**	**13370**	**14830**

Source: Kerala State Electricity Regulatory Commission

8.4.2 Analysis

KSEB adopted a method of eliminating the abnormal year 2008-09 in the projections. The Commission has noted that, in general, the annual projections of KSEB are not much far from reality, though much effort is not taken to substantiate the projection with robust analysis. The Commission has always insisted that KSEB should have a comprehensive database and robust forecasting methods for medium to long term sales projection and validation. The Commission was of the view that KSEB should not limit the load forecast for ARR purposes alone, but it should be the basis for the medium and long term planning process. Accordingly, regional forecasts of energy (MU) and demand (MW) are essentially to be developed for transmission and distribution planning. When the Commission sought the details of regional forecasts, the Board has given the reply that developing regional forecasts required large quantity of data, which cannot be processed, at the corporate level. In this context, the Commission pointed out that KSEB should be well aware of the duty cast upon them as a licensee as per section 39(2)(b) and section 42(1) of the Electricity Act 2003.

The average annual growth rate from 2003-04 to 2007-08 works out to 7.8%. A comparison of annual sales growth shows that only the energy sales for industrial consumers have been lower during power restrictions. For all other consumers, the sales were near normal even with power restrictions. The overall sales growth for HT-EHT was 5.1% and EHT alone was - 2%. Sales growth of HT-I industrial, HT-

IV Commercial, Railways, and Licensees were higher than the average growth rate. In the Low Tension sector, growth was phenomenal at 8.9%, which was mainly propelled by LT Commercial and Domestic category.

Table 8.7

Growth rate of energy sales

Category	**2003-04**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**Annual Average Growth rate**
Domestic	4004	6.4%	9.5%	11.7%	7.5%	5.9%	10.9%	7.6%	8.5%
Commercial	879	7.8%	15.3%	14.0%	10.6%	9.0%	13.6%	10.6%	11.5%
Industrial	751	4.3%	11.6%	6.9%	5.4%	3.2%	11.4%	7.1%	7.1%
Agricultural	202	-5.4%	-0.5%	15.8%	5.0%	-2.6%	5.8%	5.0%	3.1%
Street Lights	166	10.2%	13.7%	10.1%	8.7%	18.1%	3.7%	6.6%	10.1%
Sub total LT	**6002**	6.1%	10.5%	11.5%	7.7%	6.2%	11.1%	7.9%	8.7%
HT category									
HT I	1125	10.0%	10.0%	5.4%	1.7%	-9.2%	8.5%	3.2%	4.0%
HT II	130	8.5%	-7.8%	3.8%	2.2%	-22.5%	7.5%	3.5%	-1.3%
HT-III	9	0.0%	11.1%	-10.0%	0.0%	0.0%	11.1%	0.0%	1.5%
H- IV	304	11.5%	11.5%	14.0%	17.6%	14.2%	18.5%	5.4%	13.2%
EHT 66/110	1107	-6.4%	-3.1%	6.6%	-4.3%	-5.7%	14.4%	4.8%	0.6%
Railway Traction	46	-4.3%	31.8%	24.1%	51.4%	30.3%	13.4%	4.3%	20.3%
Bulk Supply	188	12.8%	39.6%	13.2%	6.6%	-11.2%	24.3%	5.8%	12.1%
Sub total HT	**2909**	3.8%	7.3%	7.7%	3.4%	-4.4%	13.5%	4.3%	5.0%
Total	**8911**	5.3%	9.4%	10.3%	6.4%	3.0%	11.7%	6.9%	7.5%

Source: Kerala State Electricity Regulatory Commission

From the above table (table 8.7) it is amply clear that the growth was propelled by the LT sector with sales growth rate close to 9%. The major contributors in the LT sector are Domestic (8.5%), Commercial (11.5%) and public lighting (10.1%). The Commission pointed out that the growth of public lighting should be viewed with caution mainly on two counts: i) it contributes to the peak load ii) the tariff levels are comparatively low (only Rs.2/kWh as per the projections of the Board). Board shall introduce energy efficient CFL/LED lamps for public lighting.

Based on the proposal from KSEB, the Commission in its order dated 2 December 2009 has revised the ToD tariff for HT-EHT categories and also introduced Maximum Demand based tariff and ToD tariff for LT industrial consumers as an optional scheme. Since the impact of peak shifting is difficult to assess, the Commission directed the Board to study and report not later than 6 months, the impact of the approved TOD tariff on peak shifting and on the revenue. It was also directed that KSEB should approach the Commission with all supporting materials, if the approved tariff has substantial financial or any other adverse impacts. Since the Board so far has not approached the Commission on this count, the Commission assumed that the new and revised schemes have a positive effect on the system.

The Board in its petition dated 25-3-2010 proposed power restrictions for two months April and May 2010. The Board proposed to impose 25% restriction on all HT&EHT consumers, LT-II, LT-IV, LT-VI(A), LT-VI(B), LT-VI (C), LT-VII (A), LT-VII(B), LT-VII (C) and to restrict domestic consumption by 200 units per month. As per the projections of the Board, due to restrictions, the consumption would reduce by 5.97 MU per day and energy requirement by 6.87 MU per day. After following the due procedure the Commission disposed of the petition by allowing 10% restrictions on all consumers except LT-VID and LT-V. In the case of domestic category the limit was fixed as 300 units/month. Accordingly, the Commission projected that the sales would be about 2.67MU less per day for the month of April and May 2010 ie., a total of 163MU. Hence the Commission assumed that energy sales would be about 163MU less than the level projected by KSEB due to power restrictions. Considering all the above, energy sales for the year 2010-11 was estimated as follows (Table-8.8):

Table 8.8

Approved Energy Sales for 2010-11

Category	Sales as per ARR (MU)	Approved Sales (MU)
LT Category		
Domestic	7078	7078
Commercial	1886	1886
Industrial	1211	1211
Agricultural	250	250
Street Lights	325	325
Sub total LT	**10750**	**10750**
HT category		
HT I	1485	1485
Category	**Sales as per ARR (MU)**	**Approved Sales (MU)**
HT II	119	119
HT-III	10	10
H- IV	723	723
EHT 66/110	1158	1158
Railway Traction	168	168
Bulk Supply	417	417
Sub total HT	**4080**	**4080**
Total	**14830**	**14830**
Less sales due to restrictions in April and May 2010		**(163)**
Net Sales		**14667**

Source: Kerala State Electricity Regulatory Commission

As part of the validation process, the Commission sought the details and methodology for month-wise projection of sales by KSEB. However, Board did not provide any data, but maintained that monthly projections were available in the ARR petition. In the absence of sufficient information, the Commission could not proceed to allocate monthly sales for the year 2010-11, which was required for estimating the additional commitment on fuel price increase. The Commission has directed KSEB , to revise the month wise energy sale based on the approved overall energy sales, and furnish the details to the Commission within one month from the date of ARR order 2010-11.

8.5 Transmission and distribution loss

8.5.1 Introduction

KSEB in its petition has stated that in between 2001-02 and 2008-09, T&D loss was reduced by 11.93% due to the sincere efforts taken by KSEB as shown below. The internal loss level projected for 2010-11 is 16.78% compared to 17.70% in 2009-10 (table 8.9).

Table 8.9

Loss reduction achieved by KSEB

Year	External loss	Extent of reduction	Internal loss	Extent of reduction
	(%)	(%)	(%)	(%)
2001-02	32.15		30.76	
2002-03	30.41	1.74	29.08	1.68
2003-04	28.46	1.95	27.44	1.64
2004-05	26.22	2.24	24.95	2.49
2005-06	24.59	1.63	22.96	1.99
2006-07	23.43	1.16	21.47	1.50
2007-08	21.63	1.80	20.02	1.45
2008-09	20.45	1.18	18.83	1.19
2009-10 (Revised projections	19.24	1.21	17.70	1.13
2010-11 (Projections)	18.53	0.71	16.78	0.92

Source: Kerala State Electricity Regulatory Commission

KSEB estimated that transmission system loss is about 5% and distribution loss is 14.55%. As per the study report of the Power Finance Corporation, the T&D losses of KSEB for the year 2007-08 was better compared to other states except Andhra Pradesh and Tamil Nadu. According to KSEB, in Tamil Nadu and Andhra Pradesh, about 20 to 30% of the consumers are unmetered and consumption is based on assessment. In the case of Kerala metering is 100% and hence estimates are more reliable. The Board has also given a calculation of Rs.790.55 Crore of saving through reduction in energy losses from 2001-02 to 2008-09. According to the Board, the target level of distribution losses stipulated by Ministry of Power at the end of 11th plan is 15%, but the distribution losses in Kerala has already reached that level. With respect to the directions issued by the Commission such as separation of transmission and distribution losses, estimate of voltage level distribution losses and separation of technical and commercial losses, the Board has forwarded a status report which was communicated to the Commission vide letter 21-11-2009. KSEB stated that the attempt to study losses through load flow analysis had failed due to inaccurate database and mismatch of meters due to difference in loading in off-peak and peak periods. A pilot study was initiated to assess the distribution losses separately in urban and rural areas with target date of completion as February 2010. Transmission losses could not be estimated because of inaccurate meters and low accuracy meters in EHT panels. The replacement of meters requires considerable capital investment and the tasks were assigned to Transmission Chief Engineers and the reports are awaited. KSEB further reported that one of the objectives of R-APDRP is to assess and segregate technical and commercial losses in the system. Part-A of the R-APDRP includes establishment of base line data using IT applications for energy accounting. The Board is in the process of replacement of faulty meters in a phased manner. After completion of these works, AT&C loss can be accurately quantified. In order to reduce the losses Board has narrated several text book steps such as reduction in LT:HT ratio, strengthening of transmission network, reconditioning of lines, capacitor compensation, realigning of LT feeders, reallocation of transformers, use of amorphous core transformers, introducing 'LT less' system, load balancing, energy audit at transformer level etc., However, no action taken report was submitted and the status of the above measures are not known. The progress of capital works in transmission & distribution and the proposed works for 2010-11 are shown below (Table-8.10):

Table 8.10
Physical Targets Achieved by the Board

Year	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10 (Revised)	2010-11 (projection)
Substations (Nos)								
220kV	1	1	1	0	1		3	2
110 kV	6	8	4	2	4	2	20	19
66kV	3	2	4	3	1		4	6
33kV	7	15	10	10	13	16	39	19
Lines (Km)								
220kV	4.3	15	56		1.01	0	29.1	28.5
110 kV	154.6	30	55	30	56.38	17.5	100	138.5
66kV	8.4	5	13	15	11.13	0	0.3	13.5
33kV	95.4	157	131	95	105.44	169.27	457.8	138
11 kV lines	1269	955	1062	1820	1807	3018	4880	3000
LT lines	4429	6074	7441	8229	8128	7636	6666	3800
Distribution Transformers (Nos)	1063	1882	1751	2124	2553	4109	5400	5000

Source: Kerala State Electricity Regulatory Commission

As in the case of previous ARR&ERC petitions, the Board narrated the usual steps being taken for reducing the commercial losses such as replacement of faulty meters, anti-power theft activities, computerization of billing and revenue collection, energy audit, loss monitoring at circle level, installing meters at transformers, feeders and border points, providing load factor and power factor incentives etc., The Board has stated that in 2009-10, target for replacement of meters was 7.44 lakhs of which 3.78 has been already completed (upto September). In 2010-11, the Board's proposal was to replace 8 lakh meters. The status of replacement of faulty meters reported by the Board is as follows (Table 8.11):

Table 8.11

Progress of faulty meters replacement

Year	No. of faculty meters replaced
2002-03	4.21
2003-04	8.67
2004-05	4.35
2005-06	6.38
2006-07	2.69
2007-08	5.80
2008-09	6.44

Source: Kerala State Electricity Regulatory Commission

Performance of the Anti power theft squad and regional audit given in the filing are compiled and shown below (Table 8.12):

Table 8.12

Performance of Anti – Power theft squad and Audit Offices

	Anti power Theft Squad				Regional Audit Office		Division/Section		
Year	Inspections	Theft cases Registered	Amount Assessed	Amount Realised	Amount assessed	Amount realized	Number of cases detected	Amount assessed	Amount realized
	(Nos)	(Nos)	(Rs. Cr)	(Rs.Cr)	(Rs. Cr)	(Rs. Cr)	(Nos)	(Rs. Cr)	(Rs. Cr)
2005-06	15611	981	21.69	9.82	14.46	4.35			
2006-07	16221	1895	12.73	11.04	14.02	7.08	18094	6.09	4.66
2007-08	18606	1144	16.93	10.5	24.72	11.94	24281	10.5	6.21
2008-09	15792	504	29.58	18.97	32.05	18.32	40612	37.76	19.2
2009-10 (up to Oct-08)	9760	196	18.85	12.00	14.26	10.99	15254	16.61	9.59

Source: Kerala State Electricity Regulatory Commission

Against the revised loss target of 18.69% for 2008-09, the actual loss reported was 18.83%. The internal T&D loss target of 17.43% proposed by the Board for 2009-10 in the previous ARR was revised to 17.70%. By strengthening the transmission and distribution system, KSEB expects reduction in losses to the tune of 1.13% in 2009-10 and 0.92% in 2010-11. Thus the loss level proposed by the Board for 2010-11 was 16.78%.

8.5.2 Analysis

The loss reduction target is one of the major performance parameters stipulated by the Commission. The Board has claimed a cumulative loss reduction of 11.93% between 2002-03 and 2008-09. However, the Consumers have strongly objected to the claims of KSEB mainly by pointing to the fact that the base level of losses were inflated in 2001-02, which was only below 18% in 2000-01. National Electricity Policy and Tariff Policy aims at faster reduction in losses to protect the interest of the consumers. The Forum of Regulators (FOR) in their deliberations stressed the need for aggressive reduction of AT&C losses. The Sub Committee of Forum of Regulators on "Methods of loss reduction" has suggested that loss reduction target of not less than 10% of the current level to be set if the current loss level is above 20% (ie., 2% reduction every year). It is also pertinent to point out that the Board could not achieve the proposed loss reduction in any of the ARR&ERC petitions in the last 6 years. Kerala is a 100% metered State with low level of non-technical losses compared to other states. However, so far the Board did not initiate a comprehensive exercise to assess the base level of T&D loss in the State. In the absence of any reliable studies on loss level, the loss reduction targets proposed by the Board is more of an assumption than realistic assessment. The Commission since its inception, has repeatedly given directions for carrying out loss studies at different levels for reasonable assessment of the base level of losses. In the compliance report on directives, the Board has admitted that the directions have been not complied so far. After the lapse of four years, Board has reported in the letter dated 24-11-2009 as follows:

(1) Board has made an attempt to find out transmission and distribution losses through load flow analysis. But this was not successful for want of sufficiently accurate database, issues of accuracy of meters and large number of arbitrary assumptions required. Hence Board has taken alternative steps for assessment of T&D losses.

(2) In the distribution wing a pilot study is initiated for assessment of distribution losses in 33kV/11kV and LT system as well as commercial losses, separately in urban and rural areas. the Board has targeting to complete the study by 15th February 2010.

(3) Transmission loss: to find out transmission losses accurate metered data are required. Many meters with EHV panels are of lower accuracy levels and need to be replaced with accurate meters. The Board has directed Transmission chief engineers to evolve a suitable methodology for segregation of transmission losses at different voltage levels."

The above reply shows the state of affairs in the Board in dealing with creation of basic database on the system. In the absence of such information, the rationale for investments proposed by the Board for system strengthening and expansion are quite questionable. The Commission could infer from the above reply that the transmission and distribution loss of 5% and 14.55% respectively claimed by the Board is only by a thumb rule. The contention of the Board that heavy investment is required for replacing EHV panels needs to be viewed seriously since, it shows even after providing substantial amount under R&M expenses, basic monitoring systems are not kept in sound condition. Further such approach would look lime a deliberate attempt to withhold critical information so as to escape proper scrutiny and the matter deserves in depth probe.

As noted above, the Commission faces the problem of lack of authenticity of data since the loss figures are never supported with adequate data. As per the data provided by the Board, about 45 lakhs of faulty /electromechanical meters were replaced (other than new connections) with electronic meters in the last 5 years. It is reasonable to attribute the reduction in losses to the replacement of more sensitive electronic meters, than proper strengthening of the distribution system. It has been noticed that after the introduction of electronic meters, recorded sales have been substantially improved, which could be one reason for improvement in loss reduction without corresponding reduction in technical loss. This conclusion carries more weight in the absence of any better information or supporting details provided by KSEB. Even though a wing of KSEB namely TRAC is communicating with plan and programmes for loss reduction, it is reasonably suspected that none of the such plans and programmes and consequent targeted loss reduction are seen communicated to the field office through the Chief Engineers of Transmission and Distribution wings.

The Commission also noted that the Board has taken little effort in estimating losses using the existing facilities. The Board has already invested more than Rs.500 Crore in APDRP scheme. One of the major objectives of the APDRP scheme is energy audit and systems are created for measurement of losses since funds allocation as well as incentives is based on the reduction in distribution loss. If such facilities are not properly employed to estimate the loss, it apparently points to the fact that investments made for recording such information are either faulty or not maintained properly.

The Board has always projected higher loss reduction, which was later scaled down to lower levels and the actuals will be again lower. Target for loss reduction in 2008-09 was 1.63%, which was revised to 1.32%. Against this, the actual reduction achieved in 2008-09 was only 1.19%. Similarly for 2009-10, loss reduction was projected as 1.27%, which was revised to 1.13%. In 2010-11, the Board proposed a lower target of 0.92% (Table No.8.13).

The Commission also analysed the capital expenditure proposed by KSEB in the past in relation to the loss levels. It is clear that there is no correlation between loss targets and capital expenditure proposed. Most of schemes provided under distribution are generally for providing service connection, rather than for than strengthening the distribution system.

Table 8.13

Capital expenditure in Distribution

Years	**Capital Expenditure (Rs. Crore)**			**Loss reduction Target proposed (%)**
	Proposed in ARR	**Revised**	**Actuals**	
2006-07	290.00	288.00	255.01	1.76
2007-08	464.36	386.09	284.43	1.83
2008-09	419.52	456.25	233.16	1.63
2009-10	600.64	436.40	NA	1.27
2010-11	425.00			0.92

Source: Kerala State Electricity Regulatory Commission

Lack of proper studies (to support the loss targets proposed by the Board) are proving to be costly to the Board since, the underachievement of losses would result in disallowance of excess power purchase cost during the truing up process. Hence, the Board should realise the facts and immediately initiate proper system to estimate the losses on a sound footing by giving instructions to Chief Engineers to fix section-wise loss reduction targets and to conduct month-wise monitoring of input energy into the section and revenue realisation. Best achievements have to be properly rewarded.

8.5.3 Progress of replacement of faulty meters

The Commission noted that progress in the area of replacement of faulty meters is also tardy. As against the target of 10.3 lakhs in 2008-09, only 6.44 lakhs meters were replaced. In 2009-10 target set by the Board was 8 lakhs, which was later revised to 7.44 lakhs. Against this, the achievement reported as on 30-9-2009 is only 3.78 lakhs. The Commission noted that total number of faulty meters in the system remains at very high levels (7.44 lakhs). In the letter dated 13-8-2009 on status of compliance, the Board reported that about 3.9 lakh faulty meters are expected to be faulty thus the total faulty meters will be 11.39 lakhs (single phase only). The Board also provided a plan for complete replacement of meters by March 2010 along with a purchase plan of about 17 lakh Single-phase static meters with LCD (Ref table-8.14). Mere purchase of meters at competitive rates without ensuring quality of meters is likely to increase the number of faulty meters year by year even if Crores of meters are replaced.

Table 8.14

Progress of replacement of faulty metes – Target Vs Achievement

Year	**Target given in the ARR (Lakhs)**	**Revised Target (Lakhs)**	**No. of Faulty meters actually replaced (Lakhs)**
2002-03			4.21
2003-04			8.67
2004-05		5.00	4.35
2005-06	5.00	8.50	6.38
2006-07	4.00	4.00	2.69
2007-08	4.13	6.00	5.80
2008-09	6.00	10.30	6.44
2009-10	8.00	7.44	(data not available)

Source: Kerala State Electricity Regulatory Commission

Considering the routine exercise of purchase of meters, the Commission sought year-wise details of purchase of meters, number of faulty meters reported, new connection provided, number of faulty meters replaced, total number of meters used and closing stock in the following format. Board conveniently, skipped the data on total number of purchase of meters over the years and gave only the following data (Table 8.15) which is incomplete.

Table 8.15

Purchase of meters and utilization

Year	No. of faulty meters as on 1st April	No. of faulty meters reported	Total number of meters purchased	No. of new connections provided	No. of faulty meters replaced	Total No. of meters used	Closing stock of meters as on 31st March
2002-03				355520	427000		
2003-04				391815	863536		
2004-05				548307	418791		
2005-06	497222	608445		548521	636256		
2006-07	469411	481355		478745	269844		
2007-08	680922	583630		482725	580484		
2008-09	684068	747922		482766	647282		
2009-10	784708	553400		323814	741015		
Total		**2974752**		**3612213**	**4584208**		

Source: Kerala State Electricity Regulatory Commission

The Board did not provide the critical information on number of meters purchased and closing stock of meters. The data provided by the Board shows that even after replacing considerable number of meters every year the opening position of faulty meters each year has in fact increased. This is on account of substantial number of meters becoming faulty every year, which raises the concern on the quality of meters being procured. It should also be noted with concern that from 2005-06 to 2009-10 (5 years), about 29.74 lakh meters become faulty, which is about 37% of the total number of consumers. There are reports that the new meters purchased for replacing faulty meters becoming faulty within a short time. It is alarming to note that from 2002-03 to 2009-10, Board has replaced 45.85lakh faulty meters. Assuming Rs.300 per meter, about Rs.137.52 crore has been spent on replacing faulty meters, which is being loaded on to the consumers. The Commission in the previous order observed that a large number of meters are becoming faulty regularly, which points towards the necessity of procuring high quality meters by issuing good quality specifications and ensuring the same.

8.5.4 Progress in achieving planned capital investment programme

The Commission noted that the target investments proposed by the Board in the transmission and distribution sector have never been achieved. The Board has always proposed ambitious investment programmes, later the targets were revised downwards, and the actual achievement was still less.

Table 8.16

Performance of the Board on project implementation in Transmission & Distribution

Year	**2007-08 (Proj)**	**2007-08 (Actual)**	**2008-09 (Proj)**	**2008-09 (Actual)**	**2009-10 (Proj)**	**2009-10 (Rev)**	**2010-11 (Proj)**
Substations (Nos)							
220kV	3	1	2		2	3	2
110 kV	11	4	7	2	18	20	19
66kV	1	1			5	4	6
33kV	31	13	32	16	27	39	19
Lines (Km)							
220kV	30.7	1.01	18.5	0	74	29.1	28.5
Year	**2007-08 (Proj)**	**2007-08 (Actual)**	**2008-09 (Proj)**	**2008-09 (Actual)**	**2009-10 (Proj)**	**2009-10 (Rev)**	**2010-11 (Proj)**
110 kV	114.75	56.38	119	17.5	202.3	100	138.5
66kV	36.99	11.13	15.5	0	16	0.3	13.5
33kV	170.5	105.44	375.7	169.27	318.3	457.8	138
11 kV lines	2000	1807	3941	3018	5000	4880	3000
LT lines	6000	8128	6500	7636	3800	6666	3800
Distribution Transformers (Nos)	2000	2553	4128	4109	5000	5400	5000

Source: Kerala State Electricity Regulatory Commission

As per the above table (table no. 8.16) , for 2007-08, the Board has proposed three 220 kV substations, eleven 110 kV substations and thirty-one 33 kV substations, but the achievement was only one 220kV substation, four 110 kV substations and thirteen 33kV substations. In 2008-09 as against the target of 2nos of 220kV substations, none was completed, against the target of 7 nos. (including the backlog of previous years) of 110kV substations only 2 was achieved. Against 16 nos. of 33kV substations only 16 are operational. Same is the case with construction of lines. As against the target of 30.70 km of 220 kV lines in 2007-08 achievement was only 1.01 km in 2007-08. In 2008-09 as against the target of 18.5 kms the achievement was nil. Exception is in the case of installation of transformers and construction of 11kV lines. However, the Commission is completely in the dark on the benefits of such investments made in the system.

Table 8.17

Loss reduction proposed, approved and achievement

Year	Proposed in the ARR (%)	Approved by the Commission (%)	Actual achieved by KSEB (%)
2005-06	2.72	2.72	1.99
2006-07	1.76	2.50	1.50
2007-08	1.83	2.00	1.45
2008-09	1.63	1.63	1.19
2009-10	1.27	1.00	1.13*
*proposed to be achieved as per ARR petition			

The observations of the Commission reveal the following (Table-8.17):

- The base level of losses is not firm. The present loss levels are based on the difference between total energy input and energy sales without proper backing of technical studies and hence the exact level of loss is not ascertainable
- No information is available on the separation of transmission and distribution losses or technical and commercial losses

- Loss targets are prepared without any systematic basis or capital expenditure plan and system-strengthening plan. No relation is established between the amount of investment and loss reduction
- Progress of works proposed and executed is very low, which contributes to non-achievement of targets set by the Commission.
- No systems are in place for estimation and periodic monitoring of system losses and remedial measures. Plans and targets seem to remain at the head office level only. At the field level, programmes and targets are not properly communicated.

The Board has projected an internal loss level of 16.78%, which is about 0.92% less than the revised estimates for the year 2009-10. The Commission had fixed internal loss for the year 2009-10 as 16.92%. After having deliberated on the issue in detail, the Commission is of the view that for 2010-11, the targeted loss reduction shall be 0.92% as projected by the Board, from that approved for the year 2009-10 ie.,16.92%. Accordingly, the loss target fixed for 2010-11 would be 16.00% as follows (Table no. 8.18):

Table 8.18

Loss target fixed by commission

	Proposed in the ARR	Approved by the Commission
Energy sales (MU)	14830	14667
Internal loss (%)	16.78%	16.00%
Net Energy input to KSEB System (MU)	**17821**	**17461**

Source: Kerala State Electricity Regulatory Commission

8.5.5 AT & C Loss

The Commission has repeatedly pointed out that the amount collected against the current demand has to be separated to know the actual collection efficiency. It is obvious that the collection efficiency furnished by the Board would be lower if collection against current demand is considered. In the Order on ARR & ERC for 2008-09 and 2009-10, the Commission had fixed collection efficiency as 98%. For the year 2010-11 the collection efficiency shall be 99%. Accordingly the AT&C loss target for 2010-11 shall be (table 8.19):

Table 8.19

AT&C Loss – target fixed by KSERC

	2010-11
T&D loss	16.00%
Collection efficiency	99.00%
AT&C loss	16.84%

Source: Kerala State Electricity Regulatory Commission

8.6 Review Of Annual Revenue Requirements

8.6.1 Introduction

The procedure for review and approval of Annual Review Requirement of the board is deliberated in this section by taking the typical case of the ARR approval for the year 2010 – 11. However, summary of regulatory scrutiny for the previous years is also included in the analysis. The Board has projected an Aggregate Revenue Requirement (ARR) of Rs.7503.98 Crore for 2010-11 including the return on equity. The details of expenses under different heads and the approach of the Commission are explained in the ensuing sections.

8.6.2 Generation and Power purchase

Total energy requirement of energy for 2010-11 estimated by the Board was 18230.16 MU. The peak demand estimated for the year was 3280 MW, which is an increase of 6% on a compounded basis over the peak demand met during 2007-08 (2745 MW). Two projects, Neriamangalam extension (25MW) and Kuttiadi Tail race (3.75 MW) were commissioned during 2008-09. Kuttiadi Additional extension (100 MW) was expected to commence commercial operation in March 2010.

8.6.3 Internal Generation

Based on the ten-year inflow data (from 2000-01 to 2009-10), the average inflow was estimated as 6537 MU. Based on the present reservoir storage and past trend in inflow it was estimated that 19.15 MU per day hydro generation was expected in the first two months (April and May) of the current year. Based on the 10 year average, daily average generation of 17.89MU was expected for the period from June 2010 to March 2011. Hence the total hydro availability from storage plants for the next financial year was estimated as 6607MU (19.15MU/day for two months & 17.89 MU/day from June,09 to March, 2010). In addition to this, 106 MU was expected from small hydro projects having capacity of 41.10MW and 240MU from Kuttiyadi additional extension. Thus the total expected hydro generation for the year 2010-11 was 6953.03MU. By considering 0.5% auxiliary consumption, the net hydro availability would be 6918.4MU.

In 2010-11, the Board was planning to operate BDPP and KDPP to the full available capacity. The cost of fuel was the major issue with these plants. The auxiliary consumption was taken as 2.5% of the total generation. According to the Board a total of 286.47MU was expected from BDPP and 447 MU from KDPP. ie., a total of about 733.47 MU from BDPP and KDPP. Considering the auxiliary consumption, the net energy available would be 715.13 MU. Based on the price of fuel as on 1-12-2009, the variable cost of generation was estimated as Rs.7.21/kWh for BDPP and Rs.7.37/kWh for KDPP. The total generation cost from these plants was estimated to be Rs.536.58 Crores as follows (Table-8.20):

Table 8.20
Generation and cost of BDPP and KDPP proposed for 2010-11

Generating station	Gross Generation	Auxiliary consumption	Net Generation	Variable cost	Total Variable cost
	(MU)	(MU)	(MU)	(Rs/kWh)	(Rs in Crore)
BDPP	286.47	7.16	279.31	7.21	206.54
KDPP	447.00	11.18	435.83	7.37	329.44
Total	733.47	18.34	715.13		536.58

Source: Kerala State Electricity Regulatory Commission

8.6.4 Purchase of power from Central Generating Stations (CGS)

As projected by KSEB, the present allocation from Central Generating Stations was about 1029.7 MW. In addition, NLC expansion Stage II was expected to start commercial operation from April 2010 and Koodamkulam 1st unit by June 2010 and 2nd unit by December 2010. Another project of NTPC Simhadri 2nd stage was expected to start commercial operation by February 2011. The new projects expected at the Central level are as follows (Table-8.21):

Table 8.21

New CGS expected to be commissioned during 2010-11

Name of the station	Total capacity	Allocation to KSEB	Allocated capacity	Expected date of commercial operation
	(MW)	(%)	(MW)	
NLC- Exp- Stge-II	500	14.0	70	April- 2010
Koodamkulam- NPC	2000	13.0	260	1st unit by June-10 and 2nd unit by Dec-10
NTPC- Simhadri	1000	8.0	80	Feb-11
Total	3500		410	

Source: Kerala State Electricity Regulatory Commission

The capacities available from CGS stations for the year 2010-11 and the estimated fixed cost projected by the Board are given below (table-8.22).

Table 8.22

Fixed cost commitment to CGS during 2010-11

Sl No.	Power Plant	Allotted Capacity	Fixed Cost
		(MW)	(Rs in crore)
1	Thalcher - II	415.8	175.64
2	NLC- Exp- Stage-1	58.8	34.31
3	NLC-II- Stage-1	63.0	12.67
5	NLC-II- Stage-2	90.0	19.68
6	RSTPS Stage I, II&III	306.1	87.58
7	MAPS	23.0	24.48
8	KAIGA Stg I	38.0	70.36
9	KAIGA Stg II	35.0	67.22
10	Kudankulam	266.0	283.74
11	NLC - II Exp	70.0	38.73
12	Simhadri Exp	80.0	8.40
	Total	1445.6	822.80

Source: Kerala State Electricity Regulatory Commission

The Board has stated that the fixed cost shown above is likely to increase by 67% if CERC finalises rates as per the norms applicable for the period 2009-14. The variable cost of power from central stations has been estimated based on the actuals from April 2009 to September 2009. In the case of nuclear power stations single part tariff would be applicable ie., Rs.2.00/kWh for MAPS and Rs.3.12/kWh for KAIGA. For Koodamkulam Rs.3.25/kWh was taken. The average cost of NLC expansion was adopted for new NLC Exp Stage II. The fixed and variable cost of Simhadri was taken as Rs.1.00/kWh and Rs.1.23/kWh respectively.

The capacity allocation of Central stations and the generation expected by KSEB would be as follows:

The Board has estimated the availability of energy from the Central Generating Stations as 19.71MU/day from April to May 2010, 21.86 MU per day from June to November 2010 and 24.02MU per day during December 2010 and January 2011 and 25.51MU per day during February and March 2011. Accordingly a total of 8197MU would be available at the generating bus and after the external loss 7814 MU would be available at the Kerala bus. The total energy available from CGS was estimated by KSEB as follows (Table-8.23):

Table 8.23

Energy availability from Central Generating Stations

Source	Energy scheduled at generator bus	External loss	Net Energy input into KSEB system	Fixed cost	Variable cost /kWh	Variable cost	Total cost
	(MU)	(MU)	(MU)	(Rs. Cr)	Rs./kWh)	(Rs. Cr)	(Rs. Cr)
Thalcher – II	2832.88	132.01	2700.87	175.64	1.24	351.35	526.99
NLC- Exp- Stage-1	372.92	17.38	355.55	34.31	1.20	44.75	82.34
NLC-II- Stage-1	372.52	17.36	355.16	12.67	1.28	47.68	70.71
NLC-II- Stage-2	531.96	24.79	507.17	19.68	1.28	68.09	87.77
RSTPS Stage I & II	2085.28	97.17	1988.11	87.58	1.42	296.11	431.23
MAPS	124.28	5.79	118.49	24.48			25.29
KAIGA Stg I	224.79	10.48	214.31	70.36			73.07
KAIGA Stg II	206.84	9.64	197.2	67.22			67.22
Kudankulam	915.71	42.67	873.03	283.74			283.74
NLC - II Exp	441.5	20.57	420.93	38.73	1.28	56.51	95.24
Simhadri Exp	88.1	4.11	84	8.4	1.23	10.84	19.24
Total	8196.78	381.97	7814.81	822.8	1.07	875.33	1762.83

Source: Kerala State Electricity Regulatory Commission

8.6.5 Power purchase from IPPs

In addition to CGS, RGCCPP (180 MW), BSES (157 MW) and KPCL (20MW) are the IPPs available to the State. From these plants 2069 MU is expected for the year 2010-11. The fixed cost commitments to these plants based on the past claims are Rs.9.18 Crore for KPCL, Rs.89.76 Crore for BSES and Rs.99.16 Crore for RGCCPP. The average cost of power from BSES and RGCCPP was proposed as Rs.7.16kWh and Rs.7.34/kWh respectively and for KPCL Rs.7.26/kWh was assumed based on the fuel price on 1st December 2009. The power purchase cost from IPPs estimated by the Board is as follows(Table-8.24):

Table 8.24

Cost of power purchase from IPPs

Source	Annual generation proposed (MU)	Fixed cost (Rs.Cr)	Variable Cost		Total (Rs.Cr)
			Rate (Rs/kWh)	Amount (Rs.Cr)	
RGCCPP	1010.69	99.16	7.34	741.85	841.01
BSES	922.03	89.76	7.16	660.17	749.93
KPCL	135.96	9.18	7.26	98.70	107.88
Total	2068.68	198.10		1500.72	1698.82

Source: Kerala State Electricity Regulatory Commission

In addition to the above IPPs, the Board proposed to purchase power from Wind energy generators, Ullumkal SHP and MPS Steel Co-generation Plant. Total energy expected from these sources was 135MU. The Board has entered into PPA with WEGs for 27.9 MW at Agali and Ramakkalmedu. The Board expects about 61.05 MU from WEGs @ Rs.3.14 /kWh. The estimated cost would be about Rs.19.17 crore. Ullumkal SHP with installed capacity of 7 MW would be operational from this year and the cost of purchase is now a provisional rate of Rs.2.00/kWh. The total generation expected is 34 MU at a cost of Rs.

6.80 crore. M/s MPS Steel may provide 40 MU from the plant @2.34/kWh which would be about Rs.9.55 crore (Table-8.25).

Table 8.25

Proposed generation & Cost from other IPPs

Source	Capacity (MW)	Annual generation proposed (MU)	Cost of energy (Rs/ kWh)	Total cost (Rs.Cr)
Wind IPPs	21.90	61.05	3.14	19.17
Ullumkal SHP	7.00	34.00	2.00	6.80
MP steel- Co generation plant	8.00	40.80	2.34	9.55
Total	36.90	135.85		35.52

Source: Kerala State Electricity Regulatory Commission

The proposed monthly demand supply position for the year is given in the following table (Table8.26). It is estimated that 165MU may be purchased from traders/day ahead purchase or exchanges (Table 8.26).

Table 8.26

Demand and Supply position for the year 2010-11

Month	Energy Demand (MU)	Availability (MU)					Shortages to be met through Traders/ PX (MU)
		Hydro (net)	KSEB sources thermal & Wind	CGS	IPPs	Total	
Apr-10	1535.03	593.51	73.38	591.20	212.31	1470.41	64.63
May-10	1577.34	609.34	75.81	610.91	214.49	1510.55	66.79
Jun-10	1432.69	508.81	69.02	655.84	199.02	1432.69	0.00
Jul-10	1387.44	567.63	29.22	677.70	112.89	1387.44	0.00
Aug-10	1494.62	584.51	24.43	677.70	207.98	1494.62	0.00
Sep-10	1452.32	609.48	73.38	655.84	113.62	1452.32	0.00
Oct-10	1538.96	592.05	64.60	677.70	204.60	1538.96	0.00
Nov-10	1517.31	558.65	73.38	655.84	195.55	1483.42	33.89
Dec-10	1555.12	545.92	63.07	744.50	201.64	1555.12	0.00
Jan-11	1579.42	584.14	59.19	744.50	191.60	1579.42	0.00
Feb-11	1484.04	553.50	53.49	714.26	162.80	1484.05	0.00
Mar-11	1648.85	610.8	59.19	790.7	188.02	1648.85	0.00
Total	18203.15	6918.4	718.13	8196.7	2204.53	18037.84	165.31

Source: Kerala State Electricity Regulatory Commission

Based on the above the merit order stack proposed by KSEB is as follows:

Table 8.27

Merit Order Stack as projected by KSEB

Source	Merit Order	Estimated variable cost for 2010-11 (Rs/kWh)	Source	Merit Order	Estimated variable cost for 2010-11 (Rs/kWh)
Hydel	1	0	MP steel Co-Gen	11	2.34
Thalcher - II	2	1.20	Kaiga	12	3.13
NLC - Exp	3	1.20	Kaiga- Stg-II	13	3.13
NLC-II - Stage-1	4	1.28	Wind IPP	14	3.14
NLC- Exp- Stage-II	5	1.28	Koodamkulam	15	3.25
NLCII - Stage II	6	1.28	BSES	16	7.16
NTPC- RSTPS	7	1.42	BDPP	17	7.21
MAPS	8	1.97	KPCL	18	7.26
Wind -Kanjikode	9	2.00	Kayamkulam	19	7.34
Ullumkal IPP	10	2.00	KDPP	20	7.37

Source: Kerala State Electricity Regulatory Commission

8.6.6 Transmission charges

Transmission charges payable to PGCIL proposed by the Board based on the actuals from April 2009 to September 2009 are as follows:

Table 8.28

Transmission charges payable

Sl. No.	Items	Actuals Apr-09 to Sep-09	Estimate for the year 2010-11
	Southern region		
	Transmission charges	85.54	204.92
	ULDC Charges	6.46	16.39
1	Sub total	91.99	221.31
2	NTPC Kayamkulam Transmission charges	5.64	11.27
3	Total transmission charges		232.58

Source: Kerala State Electricity Regulatory Commission

In addition to the above, income tax, incentives, water cess, foreign exchange variation, etc., are also payable to CGS and PGCIL. Based on the actual bills in the past years the Board projects the same as Rs.104.19 Crore for 2010-11.

Based on the above, total internal generation cost (excluding the cost of hydel stations) projected by the Board as Rs.536.58 Crore and power purchase cost as Rs.3824.75 Crore, totaling to an amount of Rs.4361.33 Crore i.e., about an average of Rs.2.45/kWh if internal generation and power purchase cost are taken together. The power purchase cost alone works out to 3.75/kWh. Summary of total generation and power purchase cost proposed by the Board is as follows (Table-8.29):

Table 8.29

Internal generation and Power purchase proposed by KSEB for 2010-11

Source	Energy Produced /Purchased	Auxiliary Consumption	External Loss	Net Energy Input to KSEB T&D system	Fixed Cost	Incentive, Tax, etc.	Total Variable cost	Total Cost
	MU	MU	MU	MU	Rs. Cr	Rs. Cr	Rs. Cr	Rs. Cr
KSEB Internal								
Hydel	6953.16	34.77		6918.40				
Wind -Kanjikode	3.00	0.00		3.00			0.60	0.60
BDPP	286.47	7.16		279.31			206.54	206.54
KDPP	447.00	11.18		435.83			329.44	329.44
Sub total	7689.63	53.10		7636.53			536.58	536.58
Power purchase								
(a) CGS								
Thalcher – II	2832.88		132.01	2700.87	175.64	3.34	339.95	518.92
NLC- Exp- Stage-1	372.92		17.38	355.55	34.31	3.28	44.75	82.34
NLC-II- Stage-1	372.52		17.36	355.16	12.67	10.36	47.68	70.71
NLC-II- Stage-2	531.96		24.79	507.17	19.68		68.09	87.77
RSPTS Stage I & II	2085.28		97.17	1988.11	87.58	47.54	296.11	431.23
MAPS	124.28		5.79	118.49	24.48	0.81	0.00	25.29
KAIGA Stg I	224.79		10.48	214.31	70.36	2.71	0.00	73.07
KAIGA Stg II	206.84		9.64	197.20	67.22	0.00	0.00	67.22
Kudankulam	915.71		42.67	873.03	283.74	0.00	0.00	283.74
NLC - II Exp	441.50		20.57	420.93	38.73	0.00	56.51	95.24
Simhadri Exp	88.10		4.11	84.00	8.40	0.00	10.84	19.24
IPPs								
RGCCPP	1010.69			1010.69	99.16		741.85	841.01
BSES	922.03			922.03	89.76		660.17	749.93
KPCL	135.96			135.96	9.18		98.70	107.88
Wind	61.05			61.05			19.17	19.17
Ullumkal	34.00			34.00			6.80	6.80
MP steel	40.80			40.80			9.55	9.55
Traders	165.31			165.31			82.66	82.66

PGCIL Charges								
Eastern Region				0.00	0.00	0.05	0.00	0.00
Southern Region				0.00	221.31	20.39	0.0	241.70
Kayamkulam				0.00	11.28	0.00	0.00	11.28
Sub total power	10566.62				1253.50	88.47	2482.83	3824.75
Total	**18256.25**	**53.10**	**381.97**	**17821.18**	**1253.50**	**88.47**	**3019.41**	**4361.33**

Source: Kerala State Electricity Regulatory Commission

8.6.7 Analysis

The total power generation and purchase expenses proposed by the Board for the year 2010-11 was comparatively higher than the levels in the previous years mainly on account of increases in the cost of power from the liquid fuel stations. Of the total energy requirement, about 15% (2802MU) was from the liquid fuel stations, but the cost was about 51% of the total cost (Rs. 2235 Crore), at an average rate of about Rs.8/kWh. The average cost of power including hydel stations was Rs.2.45/kWh, and excluding hydel was Rs.4/kWh. If the energy from liquid fuel stations are excluded, the average cost of power would be reduced to Rs.1.41/kWh ie., by Rs.1/kWh. As pointed out by the commission earlier, this shows the high cost of power the consumers in Kerala are forced to pay for the lack of proper planning and execution by KSEB over the years.

The analysis of the proposal of the Board on generation and power purchase in detail, which is given in the following sections.

8.6.7.1 Internal generation

The Board has estimated the hydro generation at 6953.16 MU, considering 19.51MU per day for April and May 2010. Considering the storage available, the Commission re-estimates the hydro availability for April and May 2010. The storage as on 31-4-2010 was 1202MU. The average inflow in May was 179MU. By providing 550 MU as reserve on 1-6-2010, generation possible in May would be 831MU. The Board has already generated 584MU in April. The total hydro available for April and May would be 1415MU, which works out to be an average of about 23.2MU instead of 19.15MU estimated by the Board. Hence, the Commission considered a conservative estimate of 23MU per day for April and May, 2010. Thus the estimated hydro generation for 2010-11 would be about 234MU higher than the estimates of the Board. Hence the Commission re-estimated the hydro availability at 7187 MU.

The Board has projected 733.47 MU from BDPP and KDPP at the rate of Rs.7.21/kWh and Rs.7.37/kWh. The Commission generally projects the cost of power from these stations based on the projections of KSEB and price of fuel. The Commission has already issued KSERC (Fuel Price Adjustment formula) Regulations, 2009. As per the regulation, the difference in fuel cost over the approved level will be adjusted in each quarter considering the benchmark performance parameter such as station heat rate, specific fuel oil consumption etc., The Commission as part of fixing the benchmark parameters, sought the details of station heat rate (including the heat rate prescribed by the manufacturers) and other parameters. KSEB provided the actual performance parameters up to the month of December 2009. The Commission also convened a meeting with KSEB on this issue on 16-4-2010. In the meeting, the Board presented its draft normative calculations by considering derating, PLF and other corrections, which was about 10 to 20% higher than the actual values. In the case of KDPP, the Board has stated certain assumptions have been used in the past to estimate the parameters. The Commission has directed the Board to separately provide its proposal on this. The Commission was of the view that the proposal of the Board can be considered after a consultation process. In the mean time, for the purpose of estimation, following values based on the data submitted by KSEB was used, which shall be replaced with approved normative parameters as and when it is approved by the Commission. Accordingly tentative benchmark parameters are worked out as follows (Table-8.30)

Table 8.30

KSERC Benchmark parameters for BDPP/KDPP

	BDPP	KDPP
Gross station heat rate	2000	1945
Average Calorific value of	10045	9700
Lubricant oil consumption	1.32	0.50
Price of LSHS (Rs./MT)	35000	35000
Price of Lub Oil (Rs./lt)	110	95
Auxiliary Consumption	2.5%	2.5%

Source: KSERC, Thiruvananthapuram

As per the data furnished by KSEB the average use of lubricant oil per kWh is 1.32ml/kWh and 0.5ml/kWh. The average LSHS cost as on 1st April 2010 is taken as Rs.35000/MT. The Commission also accepted the auxiliary consumption proposed by KSEB, which is 2.5% for both plants. Accordingly, the fuel cost for BDPP and KDPP was worked out as follows (Table-8.31):

Table 8.31

KSERC Benchmark parameters for BDPP/KDPP for BDPP/KDPP

	BDPP	KDPP
Heat Rate (kcal/kWh)	2,000.00	1945.00
Cal. Value (kCal/kg)	10045	9700
Net Generation (MU)	279.31	435.83
Auxiliary Consumption	2.50%	2.50%
Gross Generation	286.29	446.73
Qty. of fuel Required	57002	89575
Price of Fuel	35000	35000
Cost of fuel	199.51	313.51
Cost/kWh	**6.97**	**7.02**
Lubricant oil	1.2	0.5
Cost of Lub oil (Rs./lts)	109.52	95
Cost of lub oil (Rs./kWh)	0.13	0.05
Fuel Cost	**7.10**	**7.07**
Total Cost	203.27	315.64

Source: Kerala State Electricity Regulatory Commission

8.6.7.2 Availability of power from CGS

The Board has estimated generation from CGS stations based on the norms and target availability fixed by CERC as 8196.78MU. However, Commission notes that the auxiliary consumption factor for some CGS used by KSEB was not as per the CERC norms. CERC has revised the operational norms including auxiliary consumption for the tariff period starting from 1-4-2009. The Commission has considered the revised norms, which is as follows (Table-8.32)

Table 8.32

Existing and revised norm for CGS

	Aux. Consumption		**Availability**	
Station	**Existing norm**	**Revised norm**	**Existing norm**	**Revised norm**
Talcher	7.50%	6.50%	80%	85%
RSTPS I&II, III	7.85%	7.08%	80%	85%
NLC II -Stage II	10.00%	10.00%	75%	75%
NLC I Exp	9.50%	9.50%	75%	80%
NLC II -Stage I	10.00%	10.00%	75%	75%

Source: Statement of Reasons on Tariff Regulations published by CERC

In the tariff petition, KSEB has stated that the actual availability from CGS was lower compared to the approved quantity of generation in 2009-10. According to KSEB, the method followed by the Commission in 2009-10, does not consider factors such as fuel shortage and plant availability but considers only machine availability, which does not represent actual generation. However, KSERC found that the arguments of KSEB were unacceptable considering the fact that the actual generation from CGS for the year 2009-10 (especially from Talcher and Ramagundam) was higher than the approved quantity. Further, the Commission considered the average PLF achieved by these stations, it was not the average availability as pointed out KSEB. In the previous order the Commission used average PLF achieved by CGS for estimating the generation, since actual PLF achieved by the Stations would be a better indicator of performance and the generation availability. Further the Commission has allowed the incentives applicable to the CGS at actuals. Since incentives are based on the actual performance, it would always fair to consider the average performance over the years. The PLF represents the actual performance of the station, which takes into consideration the availability of fuel. The performance of Central Stations as given by CERC is given below (Table-8.33):

Table 8.33

Actual PLF Achieved by CGS Stations

CGS	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**Average**
Talcher	73%	82%	82%	84%	90%	94%	88%
RSTPS I&II,	92%	89%	91%	86%	89%	90%	89%
NLC II - Stage II	80%	80%	72%	72%	73%	81%	75%
NLC I Exp		54%	88%	84%	89%	89%	87%
NLC II -Stage I	83%	74%	72%	70%	57%	82%	70%

Source: Statement of reasons published by CERC

The average PLF of Central stations is much higher than the target availability norms especially in the case of Ramagundam and Talcher. The Commission also verified the actual PLF achieved by the existing CGS especially Talcher and NTPC Ramagudam, which are much higher for the year 2009-10 than the PLF used by the Commission in 2009-10. Hence, the Commission concluded that there is no reason to deviate from the methodology followed in the previous order. Hence the Commission has decided to approach the matter following the same method as used in 2009-10. Accordingly, the Commission re-estimated the generation from CGS stations as below (Table 8.34).

Table 8.34

Energy Availability from CGS

Power Plant	Projection by KSEB					Approved by KSERC		
	Allocation (MW)	Aux consumption	PLF	MU/Day	Total Energy (MU)	Aux consumption (Revised CERC Norm)	PLF	Energy available (MU)
TALCHER – II	415.80	8.50%	80%	7.76	2832.88	6.50%	88%*	2997
NLC – Exp	58.80	10.00%	80%	1.02	372.92	10.00%	87%*	372
NLCII - Stage I	63.00	10.00%	75%	1.02	372.52	10.00%	70%*	372
NLCII - Stage II	90.00	8.50%	75%	1.46	531.96	7.08%	75%*	532
NTPC (RSPTS)	306.00	8.50%	85%	5.71	2085.28	7.08%	89%*	2217
MAPS	23.00	10.00%	68.50%	0.34	124.28	10.00%	68.50%	124.28
KAIGA stage I	38.00	10.00%	75%	0.62	224.79	10.00%	75%	224.79
KAIGA stage II	35.00	10.00%	75%	0.57	206.84	10.00%	75%	206.84
Kudamkulam	266.00	10.00%	75%	4.31	915.71	10.00%	75%	915.71
NLC-Exp-II	70.00	10.00%	80%	1.21	441.5	10.00%	80%	441.5
Simhadri Exp	80.00	8.50%	85%	1.49	88.1	8.50%	85%	88.1
Total	**1,445.60**				**8196.8**			**8491.22**

*Average PLF for the past 5 years

Source: Kerala State Electricity Regulatory Commission

Board has used the actual fuel cost from April to September 2009 as the basis for arriving at the variable cost of power from CGS. As per the data submitted by the Board in the average fuel cost of the CGS stations from April to February, the Commission has arrived at the average variable cost for CGS as follows (Table-8.35)

Table 8.35

Approved Average variable cost of power from CGS

Month (2009-10)	RSTS	Talcher Stage-II	NLC Stage-I	NLC Stage-II	NLC Expansion
April	1.38	1.46	1.21	1.21	1.14
May	1.42	1.28	1.21	1.21	1.14
June	1.57	1.12	1.21	1.21	1.14
July	1.30	1.46	1.21	1.21	1.14
August	1.23	0.85	1.21	1.21	1.14
September	1.23	0.80	1.21	1.21	1.14
October	1.37	0.81	1.21	1.21	1.14
November	1.37	0.81	1.21	1.21	1.14
December	1.43	0.93	1.21	1.21	1.14
January	1.58	1.12	1.22	1.22	1.15
February	1.57	1.19	1.22	1.22	1.15
Average	**1.40**	**1.08**	**1.21**	**1.21**	**1.14**

Source: Kerala State Electricity Regulatory Commission

8.6.7.3 Energy purchase from other sources:

The Board has projected a total generation from IPPs using liquid fuel such as KPCL, RGCCP and BSES as 2093.68 MU at a total cost of Rs.1698.82 crore. The variable cost projected by KSEB for RGCCPP is Rs7.34/kWh and for BSES Rs.7.16/kWh. For the diesel plant KPCL, the variable cost was assumed as Rs.7.26/kWh. The cost of energy from other IPPs such wind (61.05MU), Ullumgal (34MU), M.P.Steel (40.8MU) was estimated at Rs.35.52 Crore. KSEB estimated that 165 MU needs to be purchased from traders/exchange at rate of Rs.5/kWh.

As per the estimates of the Commission, high cost purchase from many sources could be curtailed by about 874 MU as follows (Table-8.36):

Table 8.36

Generation and Power purchase approved for 2010-11

Sources	Proposed in the ARR(MU)		Estimates of the Commission (MU)	
	Gross Energy	Net energy Available at KSEB Bus	Gross Energy	Net energy Available at KSEB Bus
Hydel stations	6953.16	6918.40	7187	7,151.07
Wind	3.00	3.00	3.00	3.00
BDPP	286.47	279.31	286.47	279.31
KDPP	447.00	435.83	447.00	435.83
Internal Total	**7689.63**	**7636.53**	**7923.47**	**7869.20**
Thalcher – II	2832.88	2700.87	2,997.00	2,857.34
NLC – Exp	372.92	355.55	372.00	354.66
NLC-II - Stage-1	372.52	355.16	372.00	354.66
NLCII - Stage II	531.96	507.17	532.00	507.21
NTPC- RSTPS	2085.28	1988.11	2,217.00	2,113.69
MAPS	124.28	118.49	124.28	118.49
KAIGA Stg I	224.79	214.31	224.79	214.31
KAIGA Stg II	206.84	197.20	206.84	197.20
Kudamkulam	915.71	873.03	915.71	873.04
NLC- Exp-II	441.50	420.93	441.50	420.93
Simhadri Exp	88.10	84.00	88.10	83.99

CGS Total	**8196.78**	**7814.81**	**8491.22**	**8095.53**
Kayamkulam	1010.69	1010.69	1010.69	1010.69
BSES	922.03	922.03	922.03	922.03
KPCL	135.96	135.96	135.96	135.96
Wind	61.05	61.05	61.05	61.05
Ullumkal	34.00	34.00	34.00	34.00
MPS Steel	40.80	40.80	40.80	40.80
Purchase from Traders	165.31	165.31	165.31	165.31
Purchase other than CGS	**2370**	**2370**	**2370**	**2370**
Total	**18256**	**17821**	**18785**	**18335**
Energy requirement at KSEB BUS		**17821**		**17461**
Surplus		0		**874**

Source: Kerala State Electricity Regulatory Commission

Based on the merit order principle, the surplus energy should be deducted from the high cost sources. As per the merit order, the highest cost plants are the liquid fuel stations as follows (Table 8.37):

Table 8.37

Variable cost of high cost thermal power plants in Kerala

Stations	Rate (Rs./kWh)
KDPP	7.07
BDPP	7.10
BSES	7.16
KPCL	7.26
RGCCPP	7.34

Source: Kerala State Electricity Regulatory Commission

Though the RGCCP is the bottom of the merit order stack, because of compensatory share received from CGS, the pooled cost of RGCCP would be lower than Rs.7/kWh, hence, it is excluded from the list. For the other stations the cost ranges from Rs.7.00/kWh to Rs,7.30/kWh. Since all the plants are required for meeting the peak, proportionate reduction method was followed for eliminating the surplus energy (Table 8.38).

Table 8.38

High cost energy from thermal stations

Plants	Rate (Rs./kWh)	Energy Proposed (MU)	Less Surplus (MU)	Net Energy considered (MU)
BDPP	7.10	279	138	142
BSES	7.16	922	454	468
KPCL	7.26	136	67	69
KDPP	7.07	436	215	221
Total		1773	874	899

Source: KSERC's C ARR &ERC order 2010-11

Based on the above, the total power purchase approved for 2010-11 is as follows:

Table 8.39
Power purchase and generation cost approved for 2010-11

Source	Energy Produced /Purchased	Auxiliary Consumption	External Loss	Net Energy Input to KSEB T&D system	Fixed Cost	Incentive, Tax, etc.	Variable cost /Unit	Total Variable cost	Total Cost
	MU	MU	MU	MU	Rs. Cr	Rs. Cr	Rs/kWh	Rs. Cr	Rs. Cr
KSEB Internal									
Hydel	7187	36		7151					
Wind -Kanjikode	3	0		3					
BDPP	145	4		142			7.10	103.09	103.09
KDPP	227	6		221			7.07	160.08	160.08
Sub total	**7562**	**0**		**7517**				**263.17**	**263.17**
Power purchase									
(a) CGS									
Thalcher - II	2997		140	2857	175.64	3.34	1.08	322.24	501.22
NLC- Exp- Stage-	372		17	355	34.31	3.28	1.14	42.50	80.08
NLC-II- Stage-1	372		17	355	12.67	10.36	1.21	45.09	68.12
NLC-II- Stage-2	532		25	507	19.68		1.21	64.46	84.15
RSPTS Stage I	2217		103	2114	87.58	47.54	1.40	311.05	446.17
MAPS	124		6	118	24.48	0.81	-	-	25.29
KAIGA Stg I	225		10	214	70.36	2.71	-	-	73.07
Source	Energy Produced/ Purchased	Auxiliary Consumption	External Loss	Net Energy Input to KSEB T&D system	Fixed Cost	Incentive, Tax, etc.	Variable cost /Unit	Total Variable cost	Total Cost
KAIGA Stg II	207		10	197	67.22	-	-	-	67.22
Kudankulam	916		43	873	283.74	-	-	-	283.74
NLC - II Exp	442		21	421	38.73	-	1.28	56.51	95.24
Simhadri Exp	88		4	84	8.40	-	1.23	10.84	19.24
Total CGS	8491		396	8096	822.80	68.04		852.69	1,743.53
IPPs									
RGCCPP	1011			1011	99.16		7.34	741.85	841.01
BSES	468			468	89.76		7.16	334.82	424.58
KPCL	69			69	9.18		7.26	50.06	59.24
Wind	61			61			3.14	19.17	19.17

Ullumkal	34			34			2.00	6.80	6.80
MP steel	41			41			2.34	9.55	9.55
Traders	165			165			5.00	82.66	82.66
Total IPPs	1848			1848	198.10			1,244.90	1,443.00
Total purchase	10340	0	396	9944	1,020.90	68.04		2097.59	3186.53
Eastern Region					-	0.05			0.05
Southern Region					221.31	20.39			241.70
Kayamkulam					11.28	-			11.28
Sub total PGCIL	-	-	-	-	232.59	20.44	-	-	253.03
Total	17,901	-	396	17,461	1,253.50	88.48	-	2,360.75	3,702.73

Source: KSERC's C ARR &ERC order 2010-11

The total power purchase approved was 10340 MU with a cost of Rs.3186.53 Crore. The total cost of generation, power purchase and transmission cost allowed was Rs.3702.73 crore for 2010-11 against Rs. 4361.33 Crore projected by KSEB.

The Commission ordered that, KSEB shall within one month (from the date of ARR order 2010-11 dated 17 May 2010) prepare and submit to the Commission, month-wise energy generation and purchase plan based on the approved figures for the year 2010-11, in accordance with the KSERC (Fuel Surcharge Formula) Regulations. KSEB is duty bound to schedule the generation and power purchase in accordance with the principles envisaged under Section 61 so as to minimize the cost to the Consumers. KSEB shall endeavor to reduce dependence on high cost sources such as liquid fuel stations. In 2009-10, KSEB could purchase substantial amount of energy through traders/power exchange. Hence, the Commission ordered that the Board should take steps to replace the costly power from liquid fuel stations through short-term contracts through traders/power exchange judiciously through a transparent bidding process. Efforts should be taken to purchase on an average additional 50MU per month from June onwards from the traders, which would reduce the power purchase cost by about Rs.150 to Rs.200 Crores. The Board shall submit the information as per the fuel surcharge regulations periodically.

In order to insulate the licensee from hydro risk, the Commission would resort to a comprehensive review of hydro energy availability in the month of December 2010, by then the rainfall position and the shortage/surpluses if any would be reasonably established. Accordingly, KSEB shall approach the Commission with all necessary details for the review and if necessary, a reasonable proposal for short term purchase in a situation of hydro failure or reduction in availability from CGS or short fall in meeting peak load.

8.6.8 Interest and financing charges:

The Board has projected Rs.391.62 crore towards interests and finance charges for the year 2010-11. As against the borrowing of Rs.587 Crore and repayment of Rs.587.34 crore proposed in 2008-09, the actual borrowing was Rs.94.49 crore (out of which Rs.9.34 crore was on account of foreign exchange variation) and repayment was Rs.850.crore, which was made possible by utilizing the deposits made earlier for this purpose. Accordingly, the outstanding liability as on 31-3-2009 was only Rs.1100 crore only compared to Rs.2295.54 crore proposed. It was made possible by resorting to swapping of loans, borrowing from least cost options, restricting the borrowing and reduction in cost of borrowing from Govt., and preclosure of loans and bonds. The Board claimed that as against the approved interest cost of Rs.365.60 crore, the actual interest cost was only Rs.339.60 crore.

In 2009-10, Board has revised estimates on capital expenditure, borrowing and repayment. As against the proposed capital expenditure of Rs.1377.10Crore, the revised estimate was Rs.947.65 crore. The revised borrowing would be Rs.655.79 Crore against Rs.764.87 crore proposed. As per the revised estimate for 2009-10, the closing balance of loans and bonds will be Rs.1206.99 crore. The revised borrowing plan proposed by the Board for 2009-10 is as follows (Table 8.40):

Table 8.40

Summary of Borrowings & Repayments for the year 2009-10(RE)

Rs.in Crore

Item	Opening Balance as on 01.04.09		Borrowing in 2009-10		Redemption in 2009-10		Closing Balance as on 31.03.10	
	ARR	Revised	ARR	Revised	ARR	Revised	ARR	Revised
Loans from GOK	69.50	0.00	69.50	0.00	0.00	0.00	139.00	0.00
Existing Bonds	43.20	43.20	0.00	0.00	20.90	22.30	22.30	20.90
Loans from Financial Institutions	1387.61	1057.17	695.37	655.79	206.75	526.86	1876.23	1186.09
Total	**1500.31**	**1100.37**	**764.87**	**655.79**	**227.65**	**549.16**	**2037.53**	**1206.99**

Source: KSERC's C ARR &ERC order 2010-11

Based on the above the interest charges for 2009-10 was re-estimated as Rs.115.40 crore for loans and bonds.

The estimate for 2010-11 was prepared based on the revised estimates of 2009-10. The total fresh borrowing proposed in 2010-11 was Rs.450 crore, against the total capital expenditure of Rs.995.16 crore and repayment of Rs.653.35 crore proposed in 2010-11. Accordingly, the total interest charge for loans and bonds was arrived at as Rs.138.08 Crores as follows (Table 8.41)

Table 8.41

Interest Charges on Loans & Bonds proposed for 2010-11 (Rs. in Crore)

Sl. No.	Particulars	Rate of Interest (%)	Balance at the beginning of the year	Planned borrow in during the year	Planned redemption during the year	Balance out standing at the end of the year	Interest for the year
I	**Loans from Government**		**0.00**	**0.00**		**0.00**	**0.00**
II	**Loans from others secured**						
	KSE Bond	11.50 -	20.90	0.00	10.45	10.45	1.87
	REC	8.25-12.75	269.56	0.00	65.45	204.11	28.09
	LIC	9.00	18.00	0.00	2.00	16.00	1.62
	PFC	6.00 - 10.50	17.37	0.00	11.58	5.79	1.52
	Subtotal		**325.83**	**0.00**	**89.48**	**236.35**	**33.10**
III	**Loans from others unsecured**						
	IDBI	9.50 - 13.50	0.43	0.00	0.43	0.00	0.19
	STL from REC	8.25-8.5	195.00	0.00	195.00	0.00	5.15

	LIC	9.00	47.76	0.00	13.37	34.39	4.81
	REC	8.25-12.75	167.88	0.00	25.00	142.88	17.48
	KPFC	6.25-12.25	330.09 741.16	0.00 0.00	330.07 563.87	0.02	21.30
						177.29	48.93
	Additional borrowing	9.50	140.00	450.00	0.00	590.00	56.05
	Grand Total		**1206.99**	**450.00**	**653.35**	**1003.64**	**138.08**

Source: KSERC's C ARR &ERC order 2010-11

In addition, interest on security deposit (Rs.64.18 crore), interest on borrowing for working capital (Rs.95.32 crore), rebate to consumers for advance payment (Rs.14Crore), interest on provident fund balance (Rs.55.59 Crore), Cost of raising finance (Rs.1 crore), guarantee commission (Rs.3.49 crore), other bank charges (Rs.20 Crore) etc. were also proposed under "other interest charges" .

Regarding interest on working capital, the Board claimed that it should be based on normative basis, irrespective of actuals as has been done by CERC. As per the CERC norms, the interest on working capital would be allowed based on two months receivables, one and half month of fuel stock and one month O&M cost.

Accordingly, KSEB estimated the interest on Working capital as Rs.95.32 crore as follows (Table 8.42):

Table 8.42

Summary of interest and finance charges (in Crores)

Sl. No.	Description	2008-09	2009-10	2010-11
	O&M EXPENSES	1255.19	1456.63	1690.42
	Employee cost			
	A&G Expenses	135.46	155.45	171.05
	R&M Expenses	138.80	155.15	175.32
	Total	1529.45	1767.23	2036.79

	1/12th of above A	127.45	147.27	169.73
	Receivables			
	Annual Revenue	4893.02	4531.00	4867.00
	Receivables equivalent to 2 months	815.50	753.83	809.00
	Fuel including stock	322.21	330.12	334.28
	Fuel and stock equivalent to 1 ½ months	40.28	41.27	41.78
	Total Working Capital (A+B+C)	983.23	943.7	1020.51
	Interest on working capital @9.34%			95.32

Source: KSERC's C ARR &ERC order 2010-11

Thus, total interest & financing charges proposed at Rs.391.632 crore for 2010-11 as follows (Table 8.43):

Table No. 8.43

Summary of Interest and Finance Charges (Rs. in Crores)

Particulars	**2008-09**	**2009-10**			**2010-11**
	Accounts	**RR**	**SERC**	**Revised**	**Estimate**
I - Interest on outstanding Loans & Bonds	151.31	188.45	188.94	115.40	138.08
II - Interest on Security Deposit	50.50	50.50	50.50	55.35	64.18
III - Other Interest and Finance Charges					
Interest on borrowings for working	22.14	18.00	5.31	27.00	95.32
Rebate to consumers for timely payment	10.46	5.50	5.50	12.00	14.00
Interest on PF	37.93	64.88	64.88	51.34	55.59
Other Interest	0.00	0.01	0.01	0.01	0.01
Cost of raising finance:	0.03	1.00	1.00	1.00	1.00
Guarantee Commission	67.23	3.97 13.00	16.97	4.02	3.49
Bank Charges				17.00	20.00
Total of (III)	137.79	106.36	93.67	112.37	189.41
Grand Total (I+II+III)	339.60	345.31	333.11	283.12	391.62

Source: KSERC's C ARR &ERC order 2010-11

8.6.9 Analysis

The Board has claimed that the interest charges have been reduced substantially over the years due to several measures such as swapping of loans and restricting the fresh loans. It needs to be mentioned that over the years the Board has made efforts in reducing the outstanding liabilities by promptly repaying the loans. Further, the Board has parked substantial funds in short-term deposits for repayment even before they are due. The efforts on the part of the Board were cited for appreciation. However, the Commission noted that the substantial cash surplus was accumulated through lower capital expenditure, which helped KSEB to reduce the interest burden. Another reason could be the netting off of loans from the Government, which was about Rs.436.78 Crore. There was a decrease of Rs.132.95 Crores towards interest cost in 2006-07 when compared to 2005-06 a major portion of which could be attributed to the writing off of loans. The actual borrowing by KSEB was much less than what was proposed in the ARR as shown below (Table 8.44)

Table No. 8.44
Borrowings proposed and actual (2004-05 to 2008-09)

Borrowing (Rs. Crore)

Year	Proposed in ARR	Revised	Actual	Actual as % of proposed
2004-05	800.00	800	582.2	73%
2005-06	1000.0	511	379.4	38%
2006-07	600.0	536	41.1	7%
2007-08	584.6	353	3.1	1%
2008-09	587.3	390	94.5	16.1%

Source: KSERC's ARR & ERC order 2010-11

Though low interest cost gets directly transferred to lower cost of electricity, the Commission is of the view that this trend is not desirable for a growing capital-intensive industry. The reduction in outstanding liability is the result of surplus cash available, which was accumulated with lower capital investment. Further, as shown below, no long-term borrowing was necessitated since major share of the total capital expenses was funded through contribution and expenses capitalization (i.e., in 2008-09 about 80% of the capital expenditure (Refer Table 8.45). The funds available such as PF, security deposits, RoE, Depreciation, Grants, Electricity Duty etc., would be more than sufficient for meeting repayment obligation, which was the reason for the cash surplus accumulated over the years. Further nearly Rs.300 Crore was available with the Board in 2009-10 from duty collected from the consumers, which was not remitted to Government.

Table No. 8.45

Funding pattern of capital expenditure over the years

		(Rs. Crore)						
		2002-03	**2003-04**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**
1	Total capital expenses	454.59	809.09	461.92	499.93	537.45	373.71	645.19
2	IDC + Expenses capitalized	219.23	187.16	104.92	92.11	78.32	77.41	93.46
3	Contribution for cost of capital Assets	155.88	185.26	201.23	265.83	216.14	186.47	422.57
4 = 1-(2+3)	**Internal funds or net borrowing required for Capex**	**79.48**	**436.67**	**155.77**	**141.99**	**242.99**	**109.83**	**129.16**
	(2+3) as % of 1	83%	46%	66%	72%	55%	71%	80%

Source: KSERC's C ARR &ERC order 2010-11

The interest for the additional borrowing proposed by the Board for 2010-11 was Rs.56.05 Crores, considering proposed additional borrowing of Rs.450 crore for 2010-11 and Rs.140 Crore in 2009-10. It seems, while projecting Rs.56 crore as interest, Board has assumed that Rs.450 crore additional borrowing would be available in the beginning of the year itself. The Board has proposed Rs.764.87 Crore as additional borrowing in the ARR for 2009-10. The Commission in the Order for 2009-10, based on the actual borrowing in the previous years, capital expenditure, and the cash surplus available, concluded that borrowing requirement would be about Rs.382.44Crore in 2009-10. As against this, as per the filing, the Board has proposed Rs.140 crore only. The Commission in its letter dated 15-1-2010 sought the details of actual borrowing upto December 2009 and plan for borrowing upto March 2010. However, Board did not provide the complete details as sought by the Commission, but provided total borrowing including short term working capital loans/overdraft etc. Based on the information given by the Board, Rs.600 Crore was availed as short term loan/over draft. Since the Board did not provide the information as sought, the Commission was compelled to proceed with the information available in the filing. For 2010-11, the Board has proposed Rs.450 Crore as borrowing. However, the Commission was of the view that, borrowing level proposed by the Board was not at all required since, substantial revenue realized from the consumers in the form of Electricity Duty was retained by the Board and used as internal sources, which was about Rs.227 crore in 2008-09. The same was revealed in the actual financial position shown above.

Considering the above and the planned redemption proposed to the tune of Rs.653.35crore and depreciation and other non-cash expenses available to the Board, the Commission concluded that the borrowing proposed to the tune of Rs.450 Crore may not be required for 2010-11. From the experience of previous years, the Commission could not judge reasonably the actual amount of capital investment to be incurred in 2010-11 against the proposed Rs.995 Crore. The Board has estimated interest for additional borrowing as Rs.56.05 Crore, apparently assuming all borrowing at the beginning of the year. Even if the projections on additional borrowings were considered, the interest for the additional borrowing would only be Rs.34.67 crore since borrowings are resorted to staggered manner.

The Board has incorporated the impact of netting off of Government loans while estimating the interest and financing charges. The Commission in its Order on ARR&&ERC for 2008-09 has taken a position that netting off in the present form would not be acceptable. Similar stand has been taken by the Comptroller and Auditor General of India. Still no conclusive decision was taken by the Government on this issue. Since the decision on netting of was delayed, Commission was not in a position to provide the interest on Government loans in the ARR in a fictitious manner, which allows the Board to have excess cash without corresponding liability. Hence, as and when netting of proposal will be decided, the Commission will consider the matter and will address the issue appropriately. Till then the issue was deferred and no provision on interest on government loan was provided in the ARR.

8.6.10 Other interest charges

Regarding other interest charges, the Commission has noted the interest on working capital projected by the Board. The Board suggested to follow the norms of CERC for estimation of interest on working capital. However, while making such proposal, the Board has failed to consider the substantial security deposits available with them in comparison with Central Generating Stations, where only LC was available as payment security mechanism. If the security deposits were also considered, the actual working capital would be negative and the interest commitment should come down as shown below (Table-8.46).

Table 8.46

Details of working capital

Sl No.	Description	2008-09 Rs. Crore	2009-10 Rs. Crore	2010-11 Rs. Crore
	O&M EXPENSES	1255.19	1456.63	1690.42
	Employee cost			
	A&G Expenses	135.46	155.45	171.05
	R&M Expenses	138.80	155.15	175.32
	Total	1529.45	1767.23	2036.79
	1/12th of above A	127.45	147.27	169.73
	Receivables			
	Annual Revenue	4893.02	4531.00	4867.00
	Receivables equivalent to 2 months	815.50	753.83	809.00
	Fuel including stock	322.21	330.12	334.28
	Fuel and stock equivalent to 1 ½ months	40.28	41.27	41.78
	Total Working Capital (A+B+C)	983.23	943.7	1020.51
	Less Security Deposits available	1069.75	1194.75	1324.75
	Net working capital (A+B+C)-D	-86.52	-251.05	-304.24

Source: KSERC's C ARR &ERC order 2010-11

Further as per the ARR Petition, for 2010-11 the Board has a net negative working capital of about Rs.5435.84 crore, which shows that Board was doing business with consumers advance money and no funds of the Board was blocked on this account. Considering this position, the Commission was of the view that there was no justification for proposing such high level of interest for working capital. Hence, only the approved level of interest on working capital of Rs.5.31 Crore as in previous year was allowed for this year also.

The Board has proposed Rs.64.18 Crore on interest on security deposits as it expects that the outstanding as on 1-4-2009 would be Rs.1069.75 Crore. The Commission sought the details of debts and deposits for 2010-11, in which Board has shown the addition to security deposit as Rs.130 Crore only in 2010-11. However, addition to security deposits for the year 2009-10 itself was about Rs.147.32 crore as per the ARR. Since the Board provided not much information, the Commission agreed to the proposal of the Board. Similarly, the Board estimated Rs.14 crore towards rebate for advance payment by the consumers. The actual rebate paid to the consumers was only Rs.1.7 Crore in 2008-09. Considering this, the Commission has allowed Rs.2 crore on this head. Cost of raising finance, Bank charges, Guarantee Commission and interest on outstanding on provident fund balance are allowed as projected by the Board. The Commission reiterated that, these payments shall only be allowed on actual basis after the prudence check in the truing up process. Accordingly, the interest charge for 2010-11 was approved as shown below on a provisional basis considering the ambiguity in the netting off proposal.

8.7 Depreciation

The Board has estimated the depreciation for 2010-11 as Rs.532.89 Crore. The Board argued that since 2006-07, the Commission was adopting CERC norms for depreciation as per Tariff policy. KSEB further stated that FOR is yet to make modification on the depreciation rates notified by CERC for generation and transmission assets. Though KSEB follows Annual Account Rules for 2010-11, as directed by the Commission, KSEB has claimed depreciation as per CERC norms. As part of the restructuring process, KSEB formed committees to rectify the anomalies in the capitalization, and it was estimated that after rectification, an amount of about Rs.690 Crores might be added to assets at the end of the year. Hence the opening gross fixed assets for 2010-11 would be Rs.10744.62 Crore, accordingly the depreciation is worked out as follows (Table 8.47):

Table No. 8.47

Depreciation proposed by the Board for 2010-11

Asset Class	Gross Fixed Assets		Depreciation rates	Depreciation Amount	
	2009-10	2010-11		2009-10 (Estimate)	2010-11 (Estimate)
	Rs. Cr	Rs. Cr.	%	Rs. Cr	Rs. Cr.
Land and Land Rights	280.8	344.66	0	0.00	0.00
Buildings	497.3	524.37	3.34	16.61	17.51
Hydraulic Works	899.02	931.02	5.28	47.47	49.16
Other Civil Works	301.93	378.65	3.34	10.08	12.65
Plant and Machinery	3454.35	3978.72	5.28	182.39	210.08
Lines, Cable Network, etc.	3753.53	4513.04	5.28	198.19	238.29
Vehicles	13.05	16.04	9.50	1.24	1.52
Furniture and Fixtures	13.91	15.41	6.33	0.88	0.98
Office Equipments	35.22	42.7	6.33	2.23	2.70
Assets not in use	0.01	0.01			
Total	**9249.12**	**10744.62**		**459.09**	**532.89**

Source: KSERC's C ARR &ERC order 2010-11

8.7.1 Analysis

The Commission in the previous orders has taken a stand that depreciation shall be allowed as per the provisions of CERC norms, which was endorsed by the State Advisory Committee and stakeholders in general. The Central Commission has revised the depreciation norms in the tariff period for 2009-14 for Generating Companies and Transmission utilities. In the said regulations, CERC has made significant change in the manner of calculation of Depreciation. In the said regulations, the CERC has considered 12-year repayment period for long-term loans and adjusted the depreciation for the loan component in such a way that cash flow would be available to meet the repayment obligation. Accordingly the actual depreciation would increase to 4.5% to 5%, where as per the old norms it was about 3% to 3.5%.

It would be relevant to note that, KSEB in the petition proposed to follow CERC norms apparently lured by the higher cash flow available. In the past, the Board has been taking a consistent view that CERC norms are not applicable to them. The Board all along had argued that, it is mandatory on its part to keep the accounts as per the Annual Accounting Rules in force, where norms as per Government of India notification 1994 shall apply. The Policy directions issued by the Government and the request of the Government to the Commission vide letter dated 15-7-2008, were repeatedly quoted in support of the claim, in spite of serious audit objections of C&AG. Almost all the orders of the Commission on ARR&ERC and Truing up in various years have been challenged by KSEB at the Appellate Tribunal on this ground at the cost of public funds. This being the situation, the Board suddenly proposed the CERC norms with no supporting claims as to why such change in stand was required.

The Board has increased the addition to capital assets for the year 2010-11 to the tune of about Rs.690 crore in the name of rectification of accounts, which is yet to be completed. Commission found that such claims of the Board without proper supporting details would be untenable and hence cannot be admitted. Hence it was decided by the Commission to reject the addition of Rs. 1495.50 Crores for the year 2009-10. Nowhere in the history of the Board, such high level of capitalization has been recorded. In the absence of authentic data, the KSERC used average capitalisation from 2002-03 to 2008-09, which is Rs.637.21 crore for arriving at the opening GFA (Gross Fixed Assets) for the year 2010-11.

As per the para 5.3(c) of Tariff Policy, the Forum of Regulators (FOR) vide letter dated 23-6-2006 had communicated that depreciation as per CERC (Terms and conditions of Tariff) Regulations 2004 shall be applicable for distribution. FOR has not taken any decision on depreciation consequent to the revision of rates by CERC since the said regulation was applicable for the period 2004-09 only. Hence, the depreciation allowed would be subject to the revision by FOR if any.

Accordingly, Rs.485.75 Crore was estimated provisionally by KSERC as depreciation for the year 2010-11 (Table 8.48). Commission ordered that as and when properly authenticated information is provided, depreciation would be re-estimated after prudence check.

Table No. 8.48

Depreciation approved for the year 2010-11

Asset Class	2009-10		2010-11		2010-11
	GFA at the beginning of the year	Addition to GFA	GFA at the beginning of the year	Depreciation rates	Depreciation
	Rs. Cr	Rs. Cr	Rs. Cr.	%	Rs. Cr.
Land & Rights	280.8	27.21	308.01	0	0.00
Buildings	497.3	11.53	508.83	3.34	17.00
Hydraulic Works	899.02	13.63	912.65	5.28	48.19
Other Civil Works	301.93	32.69	334.62	3.34	11.18
Plant & Machinery	3454.35	223.42	3,677.77	5.28	194.19
Cable Network etc	3753.53	323.61	4,077.14	5.28	215.27
Vehicles	13.05	1.27	14.32	9.50	1.36
Furniture and Fixtures	13.91	0.64	14.55	6.33	0.92
Office Equipments	35.22	3.19	38.41	6.33	2.43
Assets not in use	0.01	-	0.01		
Total	**9249.12**	**637.21**	**9,886.33**	**4.96**	**490.53**

Source: KSERC's C ARR &ERC order 2010-11

Many objectors have raised the issue that depreciation shall not be allowed for assets created out of consumer contribution and grant. The Commission has taken a position that since replacement of assets is being carried out by the Board, providing depreciation would be justifiable. In such circumstances, when such assets are replaced, the Board should not claim the capital expenditure and should deduct the same from the capital expenditure plan. However, the Board is not practicing such steps. Hence, the Commission is of the view that there is a merit in the arguments of the objectors. Hence, this issue would be examined separately collecting the relevant facts and figures and giving opportunity for hearing to all concerned. Therefore the provision agreed to for depreciation will be treated as provisional.

8.8 Employee cost:

The Board has projected substantially high employee cost of Rs.1690.42 crore for the year 2010-11 which is about 58% higher than the approved level in 2009-10. The Board has revised the employee cost for 2009-10 as Rs.1456.63 crore by about 36% over the approved level. The total number of employees as on 31-3-2009 was reported as 27089, of which distribution sector accounts for 21690 numbers. According to the Board, the salary and terminal benefits are allowed periodically in line with the policy of the Government, which the Board cannot deny to the employees. The salary and other benefits for the serving employees are estimated at Rs.927.59 crore for 2010-11. While projecting salary & DA Board considered DA as on 31-3-2010 as 73% and for the ensuring year an addition of 18% (9% from July 10 and another 9% from Jan 2011). A provision of Rs.70 crore was given for leave encashment. In order to accommodate the salary revision due from August 2008 to workmen and from July 2008 to Officers a provision of 12% was also included as part of employee cost. To support this provision, the Board has referred to the judgment of Hon. Supreme Court dated 3-3-2009 in appeal No. 1110, 1112, 1138, 1152 and 1327 of 2007. According to the Board, as per the judgment appropriate provision for pay and allowance has to be made in the respective years in which it becomes due. Board also stated that the salary is only 12.35% of the total expenses. According to the Board the number of consumers served per employee and also employee per MU sold are the productivity parameters to be considered for evaluation of employee costs. The number of consumers per employee increased from 295 in 2003-04 to 375 in 2010-11, and employee per MU sold is 2.78 in 2003-04 and 1.86 in 2010-11. The employee cost (excluding pension) per unit of energy is 45 paise unit in 2003-04 and in 2010-11 it is 63 paise/unit. The cost of serving employees for the year 2010-11 is estimated by the Board (table 8.49) is as follows:

Table No. 8.49

Details of salary and benefits of serving employees projected by the Board

Sl No.	Particulars	2008-09 (Rs. Cr)	2009-10 (Rs. Cr)	2010-11 (Rs. Cr)
A.	Basic Pay	378.80	405.32	433.69
B.	DA at the beginning of the year *	173.18	222.93	316.59
	DA released/ provision made during the year	32.10	36.48	39.00
C	Other allowances (HRA, Project allowances)	27.33	29.85	32.00
	Over Time/ holiday wages	0.08	0.10	0.12
	Bonus	4.18	4.25	4.50
	Medical reimbursements	3.54	4.00	4.50
	Compensation	0.46	0.50	0.54
	Leave salary & Pension Contribution	0.17	0.18	0.20
	Earned Leave encashment	57.59	60.00	70.00
	Staff Welfare	0.79	0.85	1.00
D	**Additional provisions made for pay revision, due from July/Aug-2008**	81.15	95.15	114.60
E	Total	759.37	859.61	1016.74
F	Less amount capitalised from employee cost	67.22	77.57	89.15
G	Net Employee cost	692.15	782.04	927.59

Source: KSERC's ARR & RC order 2010-11

* DA as on 31-3-2008 = 38% , DA as on 31-3-2009 = 55% , DA anticipated as on 31-3-2010= 73%

The Board has also made an effort to address the criticism that the employee cost is much higher in KSEB than in other utilities. According to KSEB it is due to the fact that in other utilities cost of employees associated with operation and maintenance only is booked under employee cost and employee cost for capital works are booked separately under capital cost. However in the Board, except in construction of lines, substations and generating stations same employees are used for capital works and O&M, which inflate the employee cost artificially(Table 8.50).

Table No. 8.50

Performance parameters of the employees as furnished by the KSEB

Particulars	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
No. of employees	24766	24454	25565	25894	25110	27089	27625	27625
No. of Consumers in Lakh	73.00	78.00	83.00	87.10	90.30	93.63	98.76	103.76
Energy sold in MU	8910.80	9384.40	10905.70	12377.90	13396.60	12877.65	13870.10	14830.10
Revenue from sale of energy (Rs. in Crore)	2756.10	2917.40	3367.30	4009.70	4697.00	4893.02	4531.17	4867.25
No. of consumers / employee	295.00	319.00	324.00	337.00	359.62	345.64	357.50	375.60
Revenue/employee (Rs. Lakh)	11.10	11.90	13.20	15.50	18.71	18.06	16.40	17.62
Employee cost - serving employees (Rs. Crore)	397.50	446.70	487.60	542.10	514.90	692.15	782.04	927.59
Employee cost/unit of energy sold excluding pension (Rs/kWh)	0.45	0.48	0.45	0.44	0.38	0.54	0.56	0.63
Employee per MU of energy sold	2.78	2.61	2.34	2.09	1.87	2.10	1.99	1.86

Source: KSERC's ARR & RC order 2010-11

Another component of employee costs, pension liabilities, are projected at Rs.673.68 crore. As on 30-9-2009, the number of pensioners is 30278 and 574 employees are due to retire in the current financial year. KSEB proposes to separate the pension liabilities by creating a pension fund. As part of the restructuring process, Board has appointed a consultant to suggest an appropriate scheme for meeting pension liabilities. The size of the fund is estimated to be Rs.4520 crore. The pension liabilities for the year 2010-11 is estimated as follows (Table 8.51):

Table No. 8.51

Estimate of pension and terminal benefits for 2010-11

Particulars	2008-09 (Prov.)	2009-10 (Revised)	2010-11
	(Rs. Cr)	(Rs. Cr)	(Rs. Cr)
Monthly Pension	402.08	490.79	555.39
Commutation	25.02	26.4	28.6
DCRG	22.81	24.2	26.4
Medical, interim relief and festival allowance	2.16	2.58	3.26
Provision for pension revision	43.75	53.05	60.03
Total	495.82	597.02	673.68

Source: KSERC's ARR & RC order 2010-11

Accordingly the total employee cost projected for 2010-11 is Rs.1690.42 Crore.

8.8.1 Analysis

There was a strong criticism in the public hearing about huge employee expenses in KSEB. The staggering increase in employee cost was a concern to all the stakeholders and many have pointed out this. The Commission pointed out that Board has not taken any concrete measures in addressing this pertinent issue over the years. The Board has been impervious to the directions of the Commission as well as to the concerns expressed by the consumers on the increasing employee cost. The Commission has analysed this issue in detail. The increase in employee cost is due to uncontrolled increase in wages as well as in pensions. There was no effort to control the number of employees in the organization. Over the years (between 2004-05 to 2008-09), though the number of sanctioned places have decreased by about 5000, actual number of employees have increased by about 2600 at a rate of 11%.(Ref. Table 8.52). KSERC ordered KSEB to review these figures on an urgent basis.

Table No. 8.52

Growth in number of employees

No. of employees

Year	Sanctioned	Annual Increase (%)	Actual	Annual Increase (%)
2004-05	35870		24454	
2005-06	35870	0.0%	25565	4.5%
2006-07	30877	-13.9%	25894	1.3%
2007-08	30862	0.0%	25110	-3.0%
2008-09	30862	0.0%	27089	7.9%
Overall Increase	**-5008**	**-14.0%**	**2635**	**10.8%**

Source: KSERC's ARR & RC order 2010-11

The table below shows the category wise increase in number of employees. Over the last four years, the category wise increase in number of employees is about 20% to over 85%. Number of chief engineers have increased by 45%, Asst. Engineers or equivalent have increased by a staggering 85%, Executive Engineers by 31%, other non-technical officers by 42% and technical staff by 20%. In spite of considerable increase at all levels, the overall increase was limited to 11% on account of reduction in non-technical category to the tune of 2100 nos. (32%). KSERC concluded that KSEB is becoming more and more top heavy (table 8.53).

Table 8.53

Comparison of increase in employees based on category

Category of Employee	2004-05		2008-09		Increase (nos)		Increase (%)	
	Sanctioned	Working	Sanctioned	Working	Sanctioned	Working	Sanctioned	Working
Chairman/CMD	1	1	1	1	0	0	0%	0%
Members of Board	6	3	3	3	-3	0	-50%	0%
Chief Engineers	15	11	18	16	3	5	20%	45%
Deputy Chief Eng. or equivalent	78	67	83	79	5	12	6%	18%
Executive Engineers or equivalent	270	238	332	311	62	73	23%	31%
Asst. Exe. Engineers or equivalent	935	670	922	800	-13	130	-1%	19%
Asstt. Engineers or equivalent	2666	1539	3632	2847	966	1308	36%	85%
All non-technical -officers	1807	936	1350	1330	-457	394	-25%	42%
All other Technical staff	21446	14358	18391	17182	-3055	2824	-14%	20%
All non-technical -Non officers	8646	6631	6130	4520	-2516	-2111	-29%	-32%
Total	35870	24454	30862	27089	-5008	2635	-14%	11%

Source: KSERC's ARR & RC order 2010-11

It is also pertinent to examine whether the above increase in employees is justified with respect to the growth in the system. The installed capacity almost stagnant, annual sales increased by 32% and number of consumers increased by 20%, HT lines by 9%, and LT lines by 19% as shown below (Table 5.54):

Table- No. 8.54
Comparative growth in the system

Parameters	Unit	04-05	08-09	% increase
Hydel	MW	1843.6	1886.5	2%
Thermal (Incl. IPPs)	MW	591.6	591.6	0%
Wind	MW	2	23.9	1095%
Total	MW	2437.2	2502	3%
Annual Sales	MU	9384	12414	32%
No of Consumers	(Lakhs)	77.99	93.6	20%
Per Capita Consumption	kWh	400	470	18%
EHT lines	Ckt Kms	9924	10855	9%
EHT S/s	(Nos)	251	299	19%
HT lines	Ckt Kms	33998	41245	21%
LT lines	Ckt Kms	207711	241888	16%
Distribution transformers	(Nos)	36442	46510	28%

Source: KSERC's ARR & RC order 2010-11

The above analysis shows that the uncontrollable increase in employee cost needs urgent attention. The Commission since inception had issued several directions to KSEB to control/limit the expenses and to improve the productivity so as to justify high employee costs. However, no action has been taken till now. The Commission as part of the clarification process raised about 10 questions on employee cost. KSEB could not provide convincing answers to the queries. Since as per the estimates of the Board, the employee cost/kWh sale for 2010-11 works out to about Rs.1.14, the Commission sought the long-term steps taken to arrest the employee costs by KSEB. The Board instead of suggesting any means, justified the high level of employee cost with innovative replies. According to KSEB, cost of employees working in capital works is not completely included in capital expenses, which inflate the employee cost (revenue expenses). At present no separate employees are provided for carrying out capital works in the distribution sector. If the cost of employees executing the capital works in generation, transmission and distribution are separated; the cost of employees will be comparable to other distribution utilities. According to KSEB, the criticism on employee cost is without appreciating these facts. Further, according to the Board, comparison of per unit cost of employees is misleading in the case of Kerala, which is an industrially backward state. As part of the restructuring process M/s PFC Consulting Limited has submitted actuarial valuation report, which is under the consideration of the Government.

Commission found that the arguments put forwarded by the Board for justifying the employee expenses were neither reasonable nor logical. As per the provisions of the Act, electricity has to be supplied at a reasonable cost. Hence it is pertinent to compare the per unit cost, since that is what the consumer is ultimately concerned with. The justification that high employee cost in distribution was due to capital works is no way helpful for the Board in supporting their claim since the accounting practices followed in all SEBs are the same. Further, almost all the capital works are carried out through contractors and at the most only the supervision charges needs to be accounted. Further provision of capitalizing the employee cost is available and in 2010-11 about 9% of the employee cost is proposed to be capitalized by the Board.

Commission observed that the efforts of the Board in curtailing employee expenses are cosmetic and halfhearted. To cite an example, while finalizing the ARR&ERC for 2009-10, the Board vide letter dated 26-3-2009, stated that several steps are taken to improve the productivity of the employees by fixing responsibilities. Circulars were issued on the guidelines for promotion to the post of managerial cadres. The task of work-study on various functional areas has been entrusted to M/s Centre for Management Development. However, no update or follow-up action on the above steps has been reported in the present ARR.

It is also pertinent to verify the parameters supplied by the Board to show the improving level of productivity/efficiency. The employee per MU of energy sold increased from 1.87 in 2007-08 to 2.10 in 2008-09 & in 2009-10 it is 1.99. In 2010-11, the numbers of employees are held constant to reduce the ratio to 1.86. While estimating employee related performance parameters, the Board has excluded pension liabilities, which cannot be justified. Though the Board has repeatedly stated about the consultant's report on structuring of pension liabilities, the report was not produced before the Commission even after despite several reminders by Commission. The Commission is of the considered view that any justification provided by the Board to substantiate the increase in employee costs is self defeating unless concrete steps are taken to address the issue rather than evading it.

There is widespread criticism that the salary levels of employees in the Board are higher than that in Government or any other comparable organizations. Several objectors have pointed to the share of salaries in the total income. The following table (Table 8.55) shows the cost per employee and pension, which is self-explanatory.

Table No. 8.55

Trend of salary and pension – KSEB

Salary	**2008-09**	**2009-10**	**2010-11**	**Growth Rate**
Employee costs (Rs.Crore)	759.37	859.61	1016.74	15.7%
No. of employees	27089	27625	27625	
Average Annual Salary (Rs.lakhs)	2.80	3.11	3.68	
Average monthly salary (Rs.)	23360	25931	30671	14.6%
Pension				
Pension (Rs. Crore)	495.84	597.02	673.68	16.6%
No.of pensioners		30,278	30,852	
Average annual pension (Rs. Lakhs)		1.97	2.18	
Average monthly pension (Rs.)		16432	18197	

Source: Kerala State Electricity Regulatory Commission

The level of favourable employee indicators, if any, presented by the Board are incomplete without the status of outsourcing and contracting at different levels. For several posts vacancies exist, but the work is being outsourced and many people have been engaged on contract basis. These outsourced employees never become part of the official statistics which artificially keeps the employee indicators favourable. The Commission sought the details of category-wise number of employees on contract basis/HR basis and the expenses incurred for various years. The Board has not provided the information.

8.8.1.2. Comparison of cost structure

The Commission has to refer to the present industry status and similar benchmarks available. A comparison of cost levels with those of other states would be useful to benchmark the position of KSEB with similarly placed SEBs. Based on the study report of PFC, cost levels of various utilities for the year 2006-07 are compiled and given below. Major component of the cost is power purchase cost. In the case of Kerala, lower power purchase cost does not translate into lower overall cost due to high employee cost and other costs. Employee costs and O&M costs in Kerala are one of the highest in comparison with similar entities (Ref. Table 8.56).

Table 8.56

Comparison of cost structure of SEBs and Utilities in 2006-07

State	Utility	Total Cost Rs./kWh	Power Purchase Cost Rs./kWh	Employee Cost Rs./kWh	O&M Rs./kWh	Financing Cost Rs.kWh	Cost other than power purchase	Empl. Cost as% of total cost	Empl Cost % of other cost	T&D Loss
Bundled Utilities										
Jharkhand	JSEB	5.43	3.79	0.55	0.18	0.91	1.64	10%	33%	45%
West Bengal	WBSEB	6.56	2.64	0.40	0.13	0.84	3.92	6%	10%	30%
Himachal Pradesh	HPSEB	3.70	2.26	0.85	0.10	0.35	1.44	23%	59%	14%
Punjab	PSEB	3.70	2.43	0.63	0.12	0.53	1.27	17%	49%	23%
Tamil Nadu	TNEB	3.59	2.64	0.39	0.08	0.46	0.95	11%	41%	18%
Maharashtra	MSEDCL	4.05	3.30	0.39	0.11	0.22	0.74	10%	53%	35%
Chattisgarh	CSEB	3.13	1.80	0.66	0.26	0.28	1.33	21%	50%	36%
Kerala	KSEB	3.51	1.41	0.69	0.20	0.65	2.10	20%	33%	22%
Distribution companies										
Orissa	CESCO	3.63	2.50	0.48	0.23	0.41	1.13	13%	43%	44%
Delhi	NDPL	3.97	3.01	0.36	0.19	0.43	0.96	9%	37%	27%
Haryana	DHBVNL	3.84	3.36	0.26	0.10	0.10	0.48	7%	54%	30%
Andhra Pradesh	APCPDCL	2.75	2.39	0.15	0.07	0.20	0.36	5%	41%	15%
Karnataka	BESCOM	3.77	3.24	0.19	0.07	0.15	0.53	5%	35%	24%

Source: Kerala State Electricity Regulatory Commission

There has been a quantum jump in the employee costs since the study period, which will make the current position more unfavorable for Kerala. The Commission has made reservations in the projections of the Board. As per the Board, the basic salary will increase at 7% in 2010-11, though more than 500 employees are retiring (no increase in no. of employees projected in 2010-11). The projections of the Board do not reflect the impact of retirement on the basic pay, though cost of retiring persons was accounted in the terminal benefits. In order to account for inflation, about 18% increase in DA was provided for 2010-11. These projections would be valid only if inflation as per CPI for industrial workers grow at the same rate as that of the current year. The Commission also noticed the lack of basis for projections by the Board. The earned leave provision was estimated to increase over the years. Commission sought the methods for estimation of earned leave encashment details, the Board has given the following tables (Tables 8.57 & 8.58).

Table 8.57

Leave encashment/surrender details

		2006-07	2007-08	2008-09
1	EL encashment of serving employees	15.68	24.76	45.29
2	Terminal surrender	8.78	11.88	12.29
3	Total	24.46	36.64	57.58
4	Salaries/DA /allowances	514.64	474.07	696.83
5	One Month Salary (5/12)	42.89	39.51	58.07
6	Surrender of serving employees as a % of 1 month salary (1 /5)	37%	63%	78%

Source: KSEB, Vydhyuthi Bhavanam, Thiruvananthapuram

With the above, Board stated that EL provision is below one month salary of serving employees. However, Board could not explain the increase in the provision from 37% to 78% in the last 3 years.

Table No. 8.58

Comparison of increase in employee costs & pension liabilities

Year	Salary & benefits to serving employees	Yearly increase	Pension & other benefits to retired employees	Yearly increase	Total employee costs	Yearly increase	(%) of pension in total employee cost
	(Rs. Cr)	(%)	(Rs. Cr)	(%)	(Rs. Cr)	(%)	
(1)	(2)		(3)		(4)= (2)+(3)		(5)= (3)/(4)
2002-03	356.38		314.45		670.83		46.9%
2003-04	397.53	11.5%	390.78	24.3%	788.31	17.5%	49.6%
2004-05	446.73	12.4%	342.91	-12.2%	789.64	0.2%	43.4%
2005-06	487.65	9.2%	374.88	9.3%	862.53	9.2%	43.5%
2006-07	542.14	11.2%	355.95	-5.0%	898.09	4.1%	39.6%
2007-08	514.88	-5.0%	390	9.6%	904.88	0.8%	43.1%
2008-09	759.37	47.5%	495.84	27.1%	1255.21	38.7%	39.5%
2009-10 (Estimates)	859.61	13.2%	597.02	20.4%	1456.63	16.0%	41.0%
2010-11 (projection)	1016.74	18.3%	673.68	12.8%	1690.42	16.1%	39.9%
Rate of increase		**14.00%**		**9.99%**		**12.25%**	

Source: Kerala State Electricity Board, Vydhyuthy Bhavanam, Trivandrum

In between 2007-08 and 2008-09, the employee cost has increased by 47.5% and pension liabilities increased by 27.1%. The Board could not provide the reasons for such increase. The projection for 2009-10 and 2010-11 is made on the premise of inflated figures of 2008-09. The Commission was of the view that such increase was not reasonable by any standards. Further, inflationary trends in the economy have moderated considerably. The Commission has approved the employee cost of Rs.1069.96 crore as projected by KSEB for 2009-10. Stressing the need for curtailing the employee expenses and conveying strong signals to the management to take appropriate action, the Commission has decided to provide 7% increase over 2009-10 approved level for various items of employee expenses except DA. Two installments of DA @6% over the present level allowed for 2010-11 (Table-8.59).

Table No. 8.59

DA & Other allowances

Particulars	**2010-11**	
	Projected	**Approved**
	(Rs. Cr)	**(Rs. Cr)**
Basic pay	433.69	415.01
DA	355.59	302.96
Other allowances (HRA, Project allowances)	32.00	28.89
Over Time/ holiday wages	0.12	0.21
Bonus	4.50	3.53
Medical reimbursements	4.50	3.64
Compensation	0.54	0.75
Leave salary & Pension Contribution	0.20	0.21
Earned Leave encashment	70.00	42.80
Staff Welfare	1.00	0.70
Additional provisions made for pay revision, which is due from July/Aug-2008	114.60	
Total	**1,016.74**	**798.70**
Monthly pension	555.39	448.61
Commutation	28.60	
DCRG	26.40	
Medical, Interim relief, Festival allowance, FPS offices	3.26	
Provision for pension revision	60.03	
Total pension liabilities	673.68	
Grand total	**1,690.42**	**1,247.31**

Source: Kerala State Electricity Regulatory Commission

Any increase in employee costs above the approved levels shall be funded through efficiency gains. In the previous order, the Commission had directed the Board to initiate work-study to assess the reasonable level of employee costs, which has not been initiated. The Commission directed that Board shall within one month initiate the work-study to assess the reasonable level of employee strength and costs taking into consideration improvement in technology, possibility of outsourcing, mechanization, improved management strategies etc. The Board shall be transformed into a lean and efficient organization not only to protect the interest of the consumers, but also the existing employees.

8.9 A&G Expenses

Administration and General expenses (net of electricity duty) projected by the Board for 2010-11 is Rs.85.64 Crore against Rs.60.99 Crore for 2008-09 (actual). The Section 3(1) duty is estimated as Rs.85.4 Crore. According to the Board, A&G expenses are highly amenable to inflation and business growth. As per CERC norms, inflation of 5.72% is allowed for various expenses. The increase in A&G expenses is due to addition of new connections to the tune of 5 lakhs every year and increase in energy sales at the rate of 8% per year. The Board projected Rs.1 crore for consultancy charges for reorganization of the Board. Rs.10 Crore has been provided for advertisement for awareness programmes. The A&G expenses projected for 2010-11 is as follows (Table No.- 8.60):

Table No. 8.60

A&G expenses proposed for 2010-11

Sl.	Particulars	2008-09 Provisional	2009-10 Revised	2010-11 Estimate
1	Rents, rates and taxes	3.89	4.12	4.66
2	Insurance	0.50	0.75	0.85
3	Telephone/telex charges, etc.	3.93	4.17	4.72
4	Internet and related charges	0.01	0.06	0.07
5	Legal charges	1.74	1.98	2.24
6	Audit fees	2.25	2.65	3.00
7	Consultancy charges	0.06	1.18	1.33
8	Other Professional charges	0.51	0.55	0.62

9	Conveyance and vehicle hire charges	13.44	14.52	17.55
10	Sub Total (Total of 1 to 9)	**26.33**	**29.98**	**35.04**
11	OTHER EXPENSES			
	a) Fees and subscriptions	0.25	0.42	0.53
	d) Printing & stationary	7.25	8.12	9.18
	e) Advertisements	3.35	10.75	11.00
	f) Contributions/donations	0.33	0.42	0.48
	g) Electricity charges	3.45	3.62	4.09
	h) Water charges	0.27	0.31	0.35
	i) Entertainment	0.25	0.28	0.32
	j) Miscellaneous expenses	8.41	9.19	10.46
12	Total of Other Expenses	**23.56**	**33.21**	**36.41**
13	Freight	6.98	8.17	9.24
14	Other purchase related expenses	4.12	4.38	4.95
	Total	**60.99**	**75.74**	**85.64**
15	Ele. Duty u/s 3(I), KED Act	74.47	79.8	85.4
	GRAND TOTAL	**135.46**	**155.45**	**171.05**

Source: Kerala State Electricity Regulatory Commission

8.9.1 Analysis

The Commission noted the over projection of A&G expenses by the Board. A&G expense no doubt is one of the controllable items of cost hence no escalation over inflation can be allowed for this item. The Commission noted that the actual A&G expenses for 2007-08 was only Rs.47.81 crore, where as it is projected at Rs.85.64 Crore for 2010-11, showing an increase of 21% on a compounded level. In between 2007-08 and 2008-09 A&G expenses have increased by 28%, mainly due to increase in printing & stationary, advertisements and miscellaneous expenses. The Commission sought the details of miscellaneous expenses, but the Board did not provide the exact details, instead stated that all expenses other than specifically mentioned will form part of miscellaneous expenses. The Board attributed increase in A&G expenses due to increase in number of connections and sales, with out substantiating how these factors related to A&G expenses. The Board provided Rs.10 crore for advertisement expenses. In 2008-09, where large-scale campaigns were organised on account of power restrictions, the advertisement expense was only Rs.3.35 crore. Hence, the arguments of the Board for about 21% increase in A&G expenses cannot be substantiated and it is on the higher side. The Board has stated that CERC is providing 5.37% escalation based on inflation. Considering all the factors and stressing the need to contain the expenses under this head, the Commission has sealed the A&G expenses for 2010-11 at a level of 6% compounded increase over actual expenses in 2008-09 and ordered that the Board shall limit the A&G expenses at this level and under any circumstances shall not exceed this amount without proper justification. In the case of advertisements, the KSERC has agreed to Rs.4 Crore for the campaign for promoting energy efficiency and efficient energy use as requested for the Board. Accordingly the A&G expenses approved for 2010-11 is as follows (Table-8.61):

Table No. 8.61

A&G Expenses approved for 2010-11

Sl. No.	Particulars	2007-08	2008-09	2009-10	2010-11	2010-11
		Actual	Actual	Approved	ARR	Approved
1	Rents, rates and taxes	3.45	3.89	4.46	4.66	4.37
2	Insurance	0.6	0.50	1.21	0.85	0.56
3	Telephone/telex charges, etc.	3.6	3.93	4.37	4.72	4.42
4	Internet and related charges	0.01	0.01	0.07	0.07	0.01
5	Legal charges	2.42	1.74	5	2.24	1.96
6	Audit fees	2.27	2.25	2.15	3.00	2.53
7	Consultancy charges	0.06	0.06	0.2	1.33	0.07
8	Other Professional charges	0.4	0.51	0.42	0.62	0.57
9	Conveyance and vehicle hire charges	11.21	13.44	15.74	17.55	15.10
10	Sub Total (Total of 1 to 9)	24.01	**26.33**	33.6	**35.04**	29.58
11	OTHER EXPENSES					
	a) Fees and subscriptions	0.48	0.25	0.29	0.53	0.28
	d) Printing & stationary	4.2	7.25	4.33	9.18	8.15
	e) Advertisements	0.92	3.35	0.75	11.00	4.00
	f) Contributions/donations	0.78	0.33	1.00	0.48	0.37
	g) Electricity charges	3.38	3.45	3.74	4.09	3.88
	h) Water charges	0.11	0.27	0.17	0.35	0.30
	i) Entertainment	0.18	0.25	0.31	0.32	0.28
	j) Miscellaneous expenses	6.2	8.41	8.84	10.46	9.45
12	Total of Other Expenses	16.25	**23.56**	19.43	**36.41**	26.71
13	Freight	5.3	6.98	7.81	9.24	7.84
14	Other purchase related	2.25	4.12	3.39	4.95	4.63
	Total	**47.81**	**60.99**	**64.22**	**85.64**	**68.76**

Source: Kerala State Electricity Regulatory Commission

As per the Order of the APTEL, Electricity duty under Section 3(1) is not included in A&G expenses. KSEB suggested that KSEB need not take up this issue before the Commission henceforth.

8.10 Repair and maintenance Expenses:

There was no objection raised by any consumer as far R&M expenses are concerned. There was a general perception among the consumers that maintenance practices in KSEB need to be improved in view of recent mishap that occurred in Panniyar, Moozhiyar etc.

Table No. 8.62

Growth in R&M Expenses

Function	**R&M Expenses (Rs. Crore)**			
	2007-08	**2008-09**	**2009-10**	**2010-11**
Generation	7.02	14.92	20.93	24.47
Transmission	29.75	36.65	34.91	37.40
Distribution	78.33	86.30	98.54	112.67
Others	1.16	0.93	0.77	0.78
Total	**116.26**	**138.80**	**155.15**	**175.32**
Annual Growth rate				
Generation		113%	40%	17%
Transmission		23%	-5%	7%
Distribution		10%	14%	14%
Others		-20%	-17%	1%
Total		**19%**	**12%**	**13%**

Source: Kerala State Electricity Regulatory Commission

As per the details given by the Board (Ref. Table 8.62) the Commission has attempted to correlate the growth rate in the system with the R&M expenses. As shown in the table below (Table 8.63), the growth in physical infrastructure is not commensurate with the growth in R&M expenses. Growth in the installed capacity over the last four years is less than 1%, annual sales, and growth of lines and transformers is between 2.2% to 6.8%, where as R&M expenses projected are at 13% on a compounded level.

Table No. 8.63

Growth of the power system

Year		**2005-06**	**2006-07**	**2007-08**	**2008-09**	**CAGR**
Installed capacity (within the State)	Hydel (MW)	1849.60	1849.60	1851.60	1886.50	0.7%
	Thermal (Incl. IPPs) (MW)	591.60	591.60	591.60	591.60	0.0%
	Wind (MW)	2.00	2.00	2.00	23.90	128.6%
	Total (MW)	2443.20	2443.20	2445.20	2502.00	0.8%
Annual Sales	MU	10906	11331	12050	12414	4.4%
No of Consumers	(Lakhs)	82.98	87.14	90.3	93.6	4.1%
Per Capita Consumption	kWh	427	465	470	470	3.2%
EHT lines	Ckt Kms	10178	10593	10650	10855	2.2%
EHT S/s	(Nos)	269	276	281	299	3.6%
HT lines	Ckt Kms	35060	37891	38227	41245	5.6%
LT lines	Ckt Kms	215152	223370	234252	241888	4.0%
Dist transformers	(Nos)	38193	39872	42401	46510	6.8%

Source: Kerala State Electricity Regulatory Commission

In the absence of proper details to quantify the required R&M expenses, the KSERC approved Rs.161.47 crore which is 1.69% of GFA re-estimated by the Commission (Table 8.64). This estimate makes about 5.7% increase over the approved level in 2009-10, and may amply cover the inflation as proposed by the Board.

Table No. 8.64

R&M Expenses approved for the year 2010-11

Asset Category	R&M expenses proposed in the ARR	Revised GFA at the beginning of the year	R&M Expenses Approved	%of GFA
	Rs. Crore	Rs. Crore	Rs. Crore	
Buildings	4.92	508.83	4.53	0.94%
Hydraulic Works	2.12	912.65	1.95	0.23%
Other Civil Works	6.25	334.62	5.76	1.65%
Plant & Machinery	47.63	3,677.77	43.87	1.20%
Cable Network etc	107.49	4,077.14	99.00	2.38%
Vehicles	6.01	14.32	5.54	37.47%
Furniture and Fixtures	0.28	14.55	0.26	1.82%
Office Equipments	0.62	38.41	0.57	1.45%
Total	**175.32**	**9,578.31**	**161.47**	**1.69%**

Source: Kerala State Electricity Regulatory Commission

The higher provision of R&M can be justified only if performance benchmarks are achieved progressively. The Commission has already introduced standards of performance for distribution licensees. The Commission has directed the Board to provide the base level of SoP achieved by the Board, which is yet to be furnished. In its absence, it is difficult to assess the R&M requirement for maintaining the standards. Hence, the Board shall with all supporting details provide the actual base level of performance standards at the sections for the year 2009-10, by the end of the first quarter of 2010-11. Commission ordered that unless such details are provided, any increase in R&M expenses cannot be entertained. Similar exercise would be extended for Generation and Transmission also.

8.11 Return on Equity

The Board has projected the return on equity of Rs.286.99 crore for 2010-11. According to the Board, the Tariff Policy and CERC regulations permit them to claim a return on the 30% contribution made from its internal resources. From 2010-11 onwards KSEB is giving due attention on capital investment and it is finding it difficult to meet the fund requirements for 30% contribution. Hence from

2010-11 onwards return as per CERC norms for the investment made by KSEB from its own resources has to be allowed. Accordingly, KSEB estimated that of the capital expenditure proposed of Rs.995.17 crore, 30% ie., Rs.298.55 crore is treated as from own resources. Thus the total equity will be Rs.1851.55 crore. As per the revised CERC norms the return on equity is at 15.5%, thus Rs.286.99 crore is claimed as RoE. In support of the claim KSEB has also provided a copy of the letter from the Secretary, Ministry of Power Government of India, which expresses concern over the state utilities foregoing the permissible RoE. According to KSEB, in the said letter, the Central Government had directed the State Governments to issue directions to SERCs to initiate regulatory initiatives in line with CERC Tariff Regulations, 2009.

8.11.1 Analysis

The proposal of KSEB that 15.5% return on normative Debt Equity Ratio is surprising. The Commission has given a thought to the contentions of KSEB so as to examine its legality. According to the Board it is difficult to meet the funds for capital expenditure to maintain DE ratio of 70:30. In the petition KSEB estimated that Rs.286.99 Crore should be the investment from own sources in 2010-11. Generally returns are allowed/claimed for the amount actually invested in the regulated business. In this case KSEB has not made any investment. Further no evidence is available that 30% of the funds have been generated from own sources. In this respect it is interesting to see the provision in the CERC Regulations, 2009. Clause 3(2), which is as follows:

Clause 3(2) 'expenditure incurred' means the fund, whether the equity or debt or both, actually deployed and paid in cash or cash equivalent, for creation or acquisition of a useful asset and does not include commitments or liabilities for which no payment has been released;

KSEB's claims do not fall under the above definition. The guiding principles on determination of tariff under Clauses (a) to (h) of the Section 61 of the Act are as follows:

(a) commercial principles

(b) competition, efficiency, economical use of resources, good performance and optimum investments

(c) balance between consumer interest and recovery of the cost of electricity in a reasonable manner

(d) reward of efficiency of performance

(e) multi-year tariff principles

(f) tariff progressively reflects cost of generation and reduces cross subsidies

(g) promotion of cogeneration and generation from renewable resources

(h) National Electricity Policy

(i) Tariff Policy

Para 5.8.5 of the National Electricity Policy provides as under:

"All efforts will have to be made to improve the efficiency of operations in all the segments of the industry. Suitable performance norms of operations together with incentives and disincentives will need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. This will ensure protection of consumer interests on the one hand and provide motivation for improving the efficiency of operations on the other."

Hence, KSEB must realize that the provisions in the Regulations, need not automatically make them eligible to get return which are passed on to the consumers. The Board has no right or permission under the regulations to claim returns without any basis. The regulations are clear in this respect that the licensees/generating companies become eligible for return on their investment based on the performance. No regulation guarantees any return for non-performance.

Hence, in a performance based regulatory regime, return on equity is not a right of the licensee, but it has to be directly linked with the fulfillment of the duty cast upon the licensee and the efficiency with which they carryout such business. The intention of the Act, Policies and Regulations is very clear in this respect. The generating companies and licensees are ensured adequate return to attract sufficient funds for investment. Adequacy of return‟ thus depends on the ability to attract investment. As far as the Commission knows, KSEB has no difficulty in attracting funds for investment. As long as KSEB exists as a monolithic entity, there is limited scope for investment by any other sector. Hence the argument based on attracting investment for a high rate of return is not sustainable.

Hence, as an interim measure, the Commission allowed a notional return of Rs.100 Crore to Board. This provision will be treated as provisional and will be refixed on the basis of real equity or what can be treated as equity for the purpose calculating return on investment, which will be submitted by the Board on the basis of a study by a reputed agency with approval of the Commission.

8.12 Expenses and Interest Capitalized

The Board has provided Rs.23.24 Crore towards interest and financing charges capitalized and Rs.94.10crore towards expenses capitalized. The Commission provisionally allowed these items in the ARR for 2010-11 as proposed by the Board.

8.13 Aggregate Revenue Requirements

The summary of Aggregate Revenue Requirements projected by the Board and approved by the Commission for 2010-11 is as follows (Table-8.64):

Table No. 8.65

Aggregate Revenue Requirements for 2010-11

2010-11 (Rs. Crore)

Items	Proposed by the Board	Approved by the Commission
Generation of Power	536.58	263.17
Purchase of power	3,824.75	3,439.56
Interest & Finance Charges	391.62	268.29
Depreciation	532.89	490.53
Employee Cost	1,690.42	1,247.31
Repair & Maintenance	175.32	161.47
Administration & General Expenses	171.05	68.76
Other Expenses	11.70	10.10
Gross Expenditure (A)	**7,334.33**	**5,949.19**
Less: Expenses Capitalized	94.10	94.10
Less: Interest Capitalized	23.24	23.24
Net Expenditure (B)	**7,216.99**	**5,831.85**
Return	286.99	100.00
ARR (D) = (B) + (C)	**7,503.98**	**5,931.85**

Source: KSERC, Thiruvananthapuram, Tariff Order 2010-11

8.14 Order of the Commission

The Commission after considering the documents placed before it and having heard the views of the stakeholders and the Board, approved an Aggregate Revenue Requirement of Rs.5931.85 Crore and a total Expected Revenue from Charges of Rs.5474.38 Crore as against Rs.7503.98 Crore and Rs.5284.38 Crore respectively projected by the Kerala State Electricity Board in the Petition TP70 of 2010 for the year 2010-11, subject to the observations and conditions mentioned in this Order. Accordingly the KSERC has arrived at a provisional revenue gap of Rs.457.47 Crore as against the revenue gap of Rs.2219.60 Crore projected by the Board. The revenue gap arrived at is subject to the adjustment based on the truing up for 2006/07, efficiency gains, adjustment of electricity duty under section 4 and the outcome of the truing up exercise pending for the years 2007-08 and 2008-09. Commission ordered that till such time, **the existing tariff will continue.**

8.15 Tariff petitions & tariff revision orders

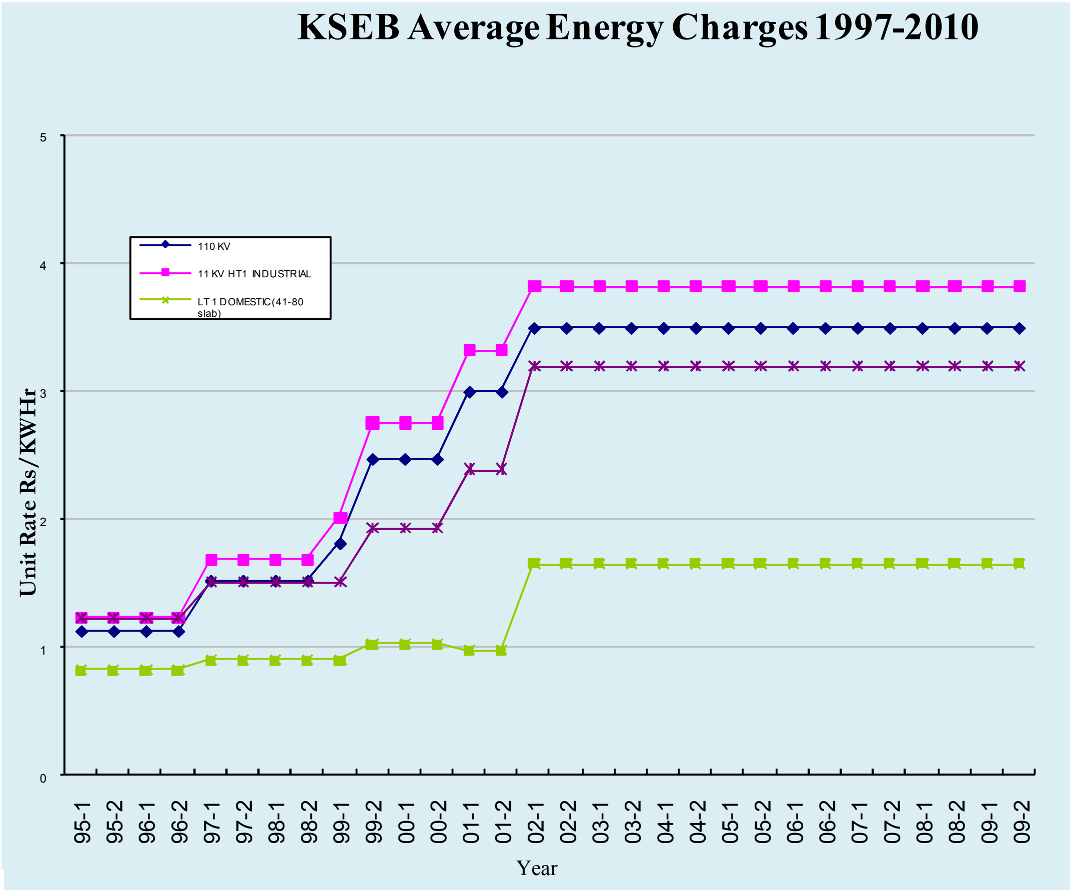
The electricity tariff for domestic consumers was reduced by 20 ps / unit with effect from 1-1-2006 by KSERC. Earlier, Government of Kerala had agreed to KSERC to release subsidy to KSEB to meet the additional expenditure incurred towards implementing the tariff reduction. GoK paid the subsidy for 3 months only. The reduction was withdrawn only during the next tariff revision in Nov. 2007. KSERC should have withdrawn the tariff reduction immediately after Government of Kerala stopped payment of subsidy to KSEB. This is a lapse on the part of KSERC.

KSEB submitted tariff proposal in June 2007 for revising the electricity tariff. An increase of Rs. 1/unit was proposed in energy charges for HT & EHT industrial electricity consumers. An increase of Rs. 70/kVA was proposed for demand charges and Rs. 1.25/unit was proposed for energy for Railway traction. Such a tariff increase would have resulted in closure of several power intensive industries working in the State for the last many decades. This was fought tooth and nail by the Industrial Electricity Consumers under the banner of Kerala HT & EHT Industrial Electricity Consumers Association. The Trade Unions also realized the danger. They also opposed the increase vehemently. The Commission issued its Order revising tariff with effect from 1-12-2007. But there was no increase for most of the categories including Domestic, HT and EHT Industrial, Commercial consumers etc. Power Intensive Industries who started functioning after 17-12-1996 was imposed with an increase of 50 paise / unit and also double the rates during peak time. Those existed prior to December 1996 were exempted from the increase.

The basic tariff structure remains the same after the constitution of KSERC in year 2002 (Ref. Figure 8.1).This is the single largest achievement of KSERC. The increase from 1997 to 2002 i.e. 7 years prior to 2002 was from 112 paise / unit to 340 paise / unit i.e. more than 200 % and there was no increase since 2002. A graph depicting the increase is attached in figure 9.1

Figure 8.1

Tariff variation 1997-2010



Source: Kerala State Electricity Board

8.16 Conclusion

As mentioned in the beginning, during the period from 2003-04 to 2010-11 KSERC has reviewed 8 tariff petitions filed by KSEB as shown in table 8.1 and issued ARR orders accordingly. There was not a single instance of tariff increase for Industrial EHT/HT Electricity consumers during the period. After scrutinising the documents submitted by the Board in the form of tariff petition with all supporting documents covering all the points mentioned the previous sections and after hearing the views of all stakeholders, the Hon'ble Regulatory Commission did not find any valid reasons for increasing tariff for the industrial consumers during the period of regulatory regime under study (i.e. 2002 to 2010) or till date. The thorough prudence check and close scrutiny of each and every items of expenditure by SERC has brought about a discipline in the functioning of KSEB. The style of independent regulatory process and independent decision-making by the KSERC on the basis of merit, after hearing the views of licensee (KSEB) as well as consumers by conducting open public hearing and inviting objections has strengthened the regulatory review as a whole. KSEB did not like the control on their activities by KSERC and the Board filed appeals at Appellate Tribunal for Electricity (ATE), New Delhi against the orders of KSERC. But most of the appeals were dismissed. An appeal on truing up was allowed partially. ARR & ERC Orders are, in effect, a thorough review of the functioning of KSEB. KSERC issued a few directives in its Order every year. Though, initially, KSEB was disregarding the directives, they have started giving explanation now for not carrying out the directives.

Arresting the steep increase in electricity tariff, which was in vogue for a decade, and maintaining it at the same level for almost another decade is the single largest achievement of KSERC. It has saved many industrials units from closure. Industries cross-subsidise heavily to other categories of consumers. Therefore, the survival of high revenue contributing industrial consumers is a must for the survival of KSEB and for the benefit of other categories of consumers. This is a great achievement of KSERC, but it is not properly realized and appreciated. KSEB has started to realize the power of KSERC, though belatedly. T & D losses and quality of power are areas of improvement. Collection of service connection charges by KSEB was declared illegal and stopped. Of course, there are areas where KSERC could not achieve much progress. Multi Year Tariff, Open Access, Reduction in Employment Cost, Open Access regulations which improve power trading in the State, Cross subsidy reduction etc. are the main such areas. But overall, the functioning of KSERC has been a grand success.

CHAPTER – 9

MAJOR FINDINGS, SUGGESTIONS AND CONCLUSIONS

9.1 Introduction

The Regulatory Commissions Act 1998 was formulated with the objective of transforming the power sector. The financial position of the State Electricity Bonds was in a poor state, mainly due to the inefficient and improper governance by State Governments. The Act envisaged constituting State & Central Electricity Regulatory Commissions for monitoring the functioning of Power Sector. The authority for approving yearly Income & Expenditure statements, revising electricity tariff etc. was vested with SERCs. The State Governments were denuded of the authority to revise tariff. Electricity Act 2003 was formulated repealing prior Acts of 1910 & 1948. The Act envisaged unbundling of SEBs functionally on the basis of generation, transmission & distribution. The ERCs were vested with sweeping powers.

The regulatory framework, regulatory review process and the impact of regulatory regime in Kerala are analysed in the previous chapters. The findings of the study, suggestions and conclusions are detailed in this chapter.

9.2 Major Findings

9.2.1 Aggregate Revenue Requirement & Expected Revenue from Charges (ARR & ERC)

ARR & ERC is the income-expenditure proposal of KSEB and other licensees for the ensuing year. KSEB and other licensees in the State started submitting ARR & ERC petitions before KSERC from 2003-2004 onwards, as directed by the Commission. The KSERC publish the petitions in its web site and seek ‘objections’ from the stakeholders. Commission conduct hearings at two or three places in the state and finally pass orders. KSEB has all along been trying to project higher ARR and lower ERC so as to project a 'revenue gap'. Initially there was mainly the HT & EHT Industrial Electricity Consumers Association to present the 'objections'. Later, Small Scale Industries Associations, Resident Associations and NGOs also started to participate. But, generally, the participation in the proceedings is poor.

The close scrutiny of each and every item of expenditure by SERC has brought about a discipline in the functioning of KSEB. ARR & ERC Orders are, in effect, a review of functioning of KSEB. Since the Board was functioning as a monopoly public sector utility till the inception of KSERC, it took a rebellious attitude towards KSERC by not complying with the directives of Regulatory Commission on several occasions as the Board did not like Regulatory Commission to control its activity. The Board filed appeals at Appellate Tribunal for Electricity (ATE), New Delhi against several orders of KSERC, but most of the appeals were dismissed. Now KSEB has started giving explanation for not carrying out the directives of Commission. However KSEB has not complied with a no. of directives issued by the KSERC. A consolidated list of directives, which await further actions from KSEB, is attached as Annexure-V.

9.2.2 Truing up

There will be some additional expenditure incurred by KSEB over and above what was approved in the ARR & ERC. The exercise of KSEB submitting a proposal for additional sanction for previous years for the additional expenditure involved is the truing up process. KSERC analyses the proposal and expenditure due to uncontrollable factors (viz. high power purchase cost due to increase in fuel prize, low rainfall etc.) are allowed and others are disallowed. This is practically an extension of the ARR & ERC Order. KSERC has been generally doing an excellent job in analyzing the expenditures and passing orders. But KSERC has not succeeded in bringing about discipline in timely passing of the orders. Truing up orders have been passed upto 2008-2009 only. The main reason is the late submission of the truing up petitions by KSEB.

9.2.3 Variation in Industrial tariff

The case study on the impact of power tariff hike and consequent closure of Indian Aluminium Company Limited (INDAL - presently known as Hindalco Industries Limited) is a classical case of oppressive, irrational and adhoc hike in tariff imposed upon industries during the pre-regulatory regime by the Government and KSEB. The hike imposed in October 2002, just a month before constituting regulatory commission in November 2002, had resulted in the closure of INDAL's smelter unit at Alupuram, Kalamassery, which was regarded as Kerala's single largest and steady consumer of electricity. The HT/EHT tariff as applicable to an Industrial Consumer like Indian Aluminium Company Limited, during the period from 1997 to 2010, is given below.

Table – 9.1

Electricity Tariff for EHT/EHT consumers

Month & Year	Tariff	PF Incentive	ToD effect	Net Tariff (Rs /Unit	Regime of KSEB / KSERC
Jan-1997	1.12	-	-	1.12	KSEB
Feb-1997	1.52	-	-	1.52	KSEB
Feb-1998	1.66	-	-	1.66	KSEB
Feb-1999	1.87	-	-	1.87	KSEB
May-1999	2.40	-	-	2.40	KSEB
Aug-2001	2.90	-	-	2.90	KSEB
Oct-2002	3.40	-	-	3.40	KSEB
Dec-2003	3.40	-	-	3.40	KSERC
Apr-2004	3.40	-	-	3.40	KSERC
Mar-2005	3.40	-	-	3.40	KSERC
Mar-2006	3.40	0.05	-	3.35	KSERC
Dec-2007	3.40	0.05	-	3.35	KSERC
Apr-2008	3.40	0.05	-	3.35	KSERC
Apr-2009	3.40	0.05	-	3.35	KSERC
Apr-2010	3.40	0.05	0.12	3.23	KSERC
Jun-2010	3.40	0.05	0.12	3.23	KSERC

Source: Tariff orders of KSEB and ARR orders of KSERC

From the table no. 9.1, it can be seen that the KSEB raised electricity tariff from Rs. 1.12 / Unit in January 1997 to Rs. 3.40 / unit in October 2002. This is equivalent an increase above 200 % from 1997 level. There was no hike in tariff during the period from November 2002 to June 2010 (the period considered for study) or even till date. This period corresponds to the regulatory regime in Kerala. Even though KSEB had made several attempts to increase the tariff of HT/EHT consumers by filing tariff petition before the Commission, the regulatory process carried out by the Commission could not find any merit in KSEB's demand. The KSERC has introduced power factor incentive in March 2006 and ToD rationalisation in December 2009. The average savings in tariff on account of PF incentive for a power intensive industrial consumer would be 5 to 7 paise per unit on an average and 10 to 12 paise per unit on an average on account of ToD rationalisation. The above incentives or relief in tariff would result in a total reduction in tariff to the tune of 17 to 20 paise per unit on an average. However, those industrial units who are unable to shift the load from peak to off peak to avail ToD benefit or who are not in apposition to improve power factor beyond the specified limit would not get this advantage.

It can seen that in comparison with the frequent and steep hike in tariff imposed upon by the KSEB as per the approval and directives of the Government during pre-regulatory period, the KSERC could maintain a steady tariff without any increase for a period of more than 8 years. KSERC had introduced incentives by rationalizing ToD tariff and introducing PF incentive as stated above. This implies that the tariff level during pre-regulatory period was exorbitant in real economic terms.

9.2.4 Capital Investments

As per KSERC (Terms & Conditions of Tariff for retail sale of Electricity) Regulations, 2006, the licensees shall *(1) propose in their filings a detailed capital investment plan covering spending on capital equipment that augments fixed assets, and capitalization of corresponding interest and expenses determined as per the applicable accounting policies and guidelines. Capital investments may address a* *variety of needs such as meeting load growth, refurbishment and replacement of equipment, reduction of losses, improvement of voltage profile, improvement of quality of supply and system reliability, metering, communication, computerization, etc. (2) The investment plan must separately show ongoing projects that will spill into the year under consideration, and new projects that will commence but may be completed within or beyond the tariff period. For the new projects, the filings must provide justification as per the guidelines prescribed by the Commission from time to time.(3) The Commission will review the licensee's investment plan for approval, and for this purpose may require the licensees to provide relevant technical and commercial details. The costs corresponding to the approved investment plan of a licensee for a given year shall, normally, be considered for its revenue requirement . (4) In addition to the approved capital investment plan, licensees can seek provision for additional capital expenditure any time during the tariff year to meet natural calamities involving substantial investments. The Commission will examine such demands and if satisfied shall approve the corresponding costs for inclusion in revenue requirement in the next period (5) In presenting the justification for new projects, the licensees shall detail the specific nature of the works, and outcomes sought to be achieved. The details must be shown in the form of physical parameters, e.g. new capacity added, to be added, meters replaced, customer service centres set up, etc., so that it is amenable to physical verification. This is necessary to ensure that the approved investment plans are implemented and the licensees do not derive improper financial benefit by delaying or neglecting to make the proposed investment. In case of any significant shortfall in physical implementation, the Commission may require the licensees to explain the reasons, and may proportionately reduce the provision, including the interest and the return component, made towards revenue requirement, in the subsequent period (6) In case a licensee proposes to set up generation projects, details of tariff calculations for the electricity generated along with full justification there of should be furnished.*

KSEB has projected capital expenditure of Rs 995.15 Crores for FY 2010-11, a considerable decrease from the impractical targets that the Board used to propose, and of course not achieve, in previous years. The main investment objectives stated by KSEB are as below:

(a) To provide quality and reliable power at affordable cost to consumers

(b) To reduce the T&D loss within the targets set out by the CEA.

(c) Improve the performance of the Board through achieving further improvements in the quality of power delivered to consumers.

(d) To provide power supply on demand to consumers and accomplish various directions and standards within the time frames set out by the KSERC.

However, it is not clear from the ARR filing for FY10-11 how the proposed investment will be implemented to achieve the objectives set by KSEB. All that has been provided is a request to allow filing of capital investment plan by end of January 2010. This has not been filed, and it is a violation of one of the main conditions of the applicable regulations. Clearly, the Board has absolutely no clue about what its capital investment program will be, and neither does it have a streamlined, efficient project management team that can deliver projects on time and within allocated budgets.

KSEB did not explain as to how the proposed investments meet the objectives set down by it. KSEB also failed to state the benefits which can be attained by the proposed investments. This is despite the Commission giving clear directions to KSEB on the approach to be followed while proposing capital investments.

The proposed capital investments need to be accompanied by the following:

(a) Detailed report explaining the cost and benefits derived from the investment like; decrease in losses, improved quality of service, etc

(b) Detailed planning of the investment covering the start and end date of the project, capitalisation schedule, etc

(c) Details of the financing pattern of the investments covering the details on the approved financing institutions, DE ratios, interest rate, repayment schedules, cost of equity invested, etc

(d) For enabling prudence check to be carried out by the Commission, the Board should also provide details of completed projects, application of budgeted funds, over/under spending of funds, etc.

The Commission had also repeatedly expressed its concern on mismanagement by the Board in project implementation. The physical and financial progress of the projects were also not submitted for periodical monitoring (with targeted and actual physical and financial achievement) to the Commission despite repeated reminders and directives.

9.2.5 Reduction in T&D Loss

Transmission and distribution loss is one of the major performance parameters monitored by the Commission. The Board has stated in the petition that loss levels have been reduced by about 11.93% between 2001-02 and 2008-09. However, as the following tables show that the actual loss levels achieved by KSEB are always lower than the levels fixed by the Commission.

Table – 9.2

T & D Loss proposed and approved

Year	Proposed in the ARR (%)	Approved level (%)	Actual (%)
2003-04	26.60	26.60	27.45
2004-05	24.47	24.50	24.95
2005-06	22.59	21.89	22.96
2006-07	21.58	20.45	21.47
2007-08	19.72	19.55	21.47
2008-09	18.49	17.92	20.02
2009-10	17.43	16.92	18.83

Source: KSERC Tariff Orders from 2003-2004 to 2009-2010

Table – 9.3

T & D Loss reduction as approved by KSERC

Year	Proposed in the ARR (%)	Approved by Commission (%)	Actual Achieved by KSEB
2005-06	2.72	2.72	1.99
2006-07	1.76	2.50	1.50
2007-08	1.83	2.00	1.45
2008-09	1.63	1.63	1.19
2009-10	1.27	1.00	1.13*
*proposed to be achieved by KSEB as per ARR petition			

Source: KSERC, Thiruvananthapuram

By the timely intervention of the Commission by fixing targets for energy loss reduction and specifying appropriate loss reduction methods, KSE Board has shown remarkable reduction in T&D loss of the system. Where ARR & ERC has been approved on MY basis, roadmap for AT & C losses also has been specified. It has been noticed that in the case of most of the small Licensees, AT & C loss is already very low and within limits and the scope of further loss reduction is limited. As far as KSEB (the major Licensee) is concerned in orders on ARR & ERC issued from the year 2004 onwards, loss reduction targets for each year has been specified and KSEB has been almost achieving the targets given. From 2004 onwards the T & D losses are getting reduced progressively as shown above.

9.2.6 Interest burden of KSEB reduced

The Board has swapped the existing high cost loans by availing fresh loans at lower interest rates resulting lower amount of interest payable. This has resulted in substantial reduction in the interest charges over the years as shown below.

Table – 9.4

Interest burden of KSEB

Year	Interest Amount (Rs. Cr)
2002-03	672.79
2003-04	726.32
2004-05	605.59
2005-06	566.48
2006-07	529.76
2007-08	356.28
2008-09	339.60
2009-10	333.11
2010-11	268.29 (Projection)

Source: KSEB, Thiruvananthapuram

The Board has been restricting fresh borrowing and repaying the loans as per schedule. However, the Commission is of the view that there exists further scope for improvement in swapping and closing out the outstanding loans to minimize the interest and the debt service burden. Also, it is more important to link the loans to specific projects and manage the projects efficiently for timely completion so that capitalization can be made effective and project deliverables/revenue can be realized in time. It was made possible by resorting to swapping of loans, borrowing from least cost options, restricting the borrowing and reduction in cost of borrowing from Govt., and pre-closure of loans and bonds

9.2.7 Energy sales forecast

The Regulatory Commission has been continuously directing the Board to provide a comprehensive database on sales for analysing the veracity of the Board's projections on energy sales. However, this remains merely on paper due to the Board's refusal to comply. The relevant extract from the Hon'ble Commissions Order on ARR & ERC for FY10 is reproduced below *"Though the Commission has continuously directed the Board to provide comprehensive database on sales for analyzing the veracity of the projections, the same was not provided nor any attempt was made to create such database. The Commission in all its previous orders had directed the Board to improve the methods of load forecast, which has not materialized so far."*

Board had claimed that since its forecast was very close to reality, its current method of forecasting sales is more than adequate, notwithstanding the explicit directive of the Regulatory Commission to provide a comprehensive database of sales. Since approved sales numbers are the starting point for determining generation & power purchase cost, which is seen to be one of the major cost items of the Board. This is especially important in the light of the Board's trend of projecting gaps running into thousands of crores on the grounds that it is being forced to purchase expensive power to satisfy demand.

9.2.8 Optimum Scheduling of Internal Generation

The Commission keeps track of the daily generation scheduling of the Board including the UI transaction by monitoring the daily system statistics and reservoir report from SLDC. The power purchase schedule on merit order basis is implemented and co-coordinated with internal hydro generation according to the requirements by the Board and the same is regularly reviewed at various levels in KSEB through appropriate management information system. The Commission expects the Board to achieve further improvement in the Optimum Scheduling of Internal Generation during FY 2010-11.

9.2.9 TOD tariff

ToD (Time of Day) tariff is techno-commercial tool used for encouraging consumers to shift their load from, peak to off peak as all utilities in India are facing peak-load crisis. KSEB has first introduced TOD tariff in 1999. Compared to TOD tariff of other states, this tariff was not a good one. KSEB considered this as another source for earning revenue. From 2003 onwards, the Industrial Consumers were clamoring for improvement of the TOD tariff. The request for modification & rationalization of the ToD tariff was constantly raised by the industrial consumers. Finally, KSERC rationalized the TOD tariff in Dec. 2009. The structure of the TOD was modified making it very simple.

Table – 9.5

ToD Tariff

	Day	*Peak*	*Off Peak*
Demand charges	100%	140%	80%
Energy charges	100%	130%	85%

Source: KSERC Order (ToD)

This was in line with TOD tariff prevailed in other States. But not attractive as those of Uttaranchal, West Bengal & Karnataka. The Industry appreciated the Order. But KSEB submitted a review petition for revising the TOD tariff pleading loss of revenue. In the public hearing, the industries requested to continue the tariff and loss of revenue, if any, should be considered at the time of main tariff revision.

The KSERC revised the TOD tariff again as follows :

Table – 9.6

Revised ToD Tariff

	Day	*Peak*	*Off peak*
Demand	100%	150%	80%
Energy	100%	140%	85%

Source: KSERC Order (ToD)

By this order, the basic principle of ToD tariff was compromised i.e. there should be proper incentive for shifting load from peak hours to off – peak hours and & disincentive for consumption during peak hours. In this case the commission has increased the penalty for peak consumption while keeping they incentive for consumption during of peak hours same as that of previous ToD scheme. By this revision, KSERC ensured more revenue for KSEB, but the requirement of DSM as well as the genuine interest of the Industrial Consumers was compromised.

9.2.10 Power factor & other Incentives

PF incentives prevailed in India in a few States for more than a decade. The request for a similar incentive scheme was finally accepted by KSERC in 2006. The incentive was 0.15% for every % increase. Maximum incentive was 1.5%. But the penalty is 1% for every % fall below 0.9. The penalty is stringent but the incentive is not attractive. In Maharashtra the maximum PF incentive is 7% and in Gujarat it is 5%. The request of the Industries to make the PF incentive & disincentive more reasonable has not been accepted so far. But it is good that such a scheme is in vogue.

Incentive Schemes for Load factor and Bulk consumption are prevailing in other States. But the request to introduce such incentives in Kerala has not been accepted by KSERC so far.

9.2.11 Power Purchase optimization and Generation Cost

Section 13 of the KSERC (Terms and Conditions of Tariff for Distribution & Retail Sale of Electricity under MYT Framework) Regulations, 2006 dated October 12 2006 clearly provides for the manner in which power purchase and associated cost will be approved. The relevant extract of the regulations is reproduced below.

"Cost of Power purchase.- (1) The Distribution Licensee shall be allowed to recover the cost of power it procures, from all the sources including the power

procurement from the State owned Generating stations, independent power producers, Central generating stations, renewable energy sources and others for supply of power to consumers, based on the Load Forecast approved by the Commission for each of the financial years of the control period. (2) For the purpose of determining the power purchase requirement of the Distribution Licensee for a control period, the Commission shall adopt the sales forecast, the distribution loss trajectory and power procurement plan approved by the Commission.(3) Approved retail sales level shall be grossed up by normative level of T&D losses as indicated in the MYT trajectory for allowing power purchase quantity. (4) While approving the cost of power purchases, the Commission shall determine the quantum of power from various sources in accordance with the principles of merit order schedule and despatch based on a ranking of all approved sources of supply in the order of variable cost. (5) All power purchase costs will be considered legitimate unless it is established that the merit order principle has been violated or power has been purchased at unreasonable rates.

In the ARR & ERC Order for FY09-10, the Commission had directed that henceforth, the inflow data over a period of 20 years would be used to estimate the inflow for the year under consideration. The relevant portion of the Hon'ble Commission's directive is reproduced below:

"Hence, the Commission is of the view that from next year onwards, the method of estimation is to be changed from 10 years to 20 years, which would reduce the influence of extreme values. Further, data for the current year (in the present case 2008-09) be excluded from calculating the average, as about 7 months data (ie., from November to May) for the current year have to be estimated as the actual is not available."

The Board has not complied with this directive of the Regulatory Commission.

However, the Commission has been regulating the power purchase of the Board on merit order basis and the Board has been very effectively implementing the same. As part of renewal of the PPA with NTPC-Kayamkulam plant, the Board was successful in its attempt to derive commercial advantage of lower rate of overall pooled cost of NTPC Kayamkulam by getting additional allocation of 180 MW with effect from 1-11-2005 from NTPC- Talcher-II from the unallocated portion.

9.2.12 Depreciation

Depreciation is accounted for in ARR as a means to generate funds for repayment of loans taken to fund capital investments. Capital investments plans are being approved separately and loans for creation of these capital assets is being allowed on normative basis, with interest on these loans being allowed separately. Subsequently, these assets will be capitalised and depreciation claimed thereon, which provides the funds needed for repayment of capital loans. When assets are created through consumer contribution, the use of internal resources and/or external borrowings is avoided. Therefore the need for depreciation on the portion of assets created through consumer contributions, in order to meet RoE or loan repayment is avoided.

When depreciation is allowed on consumer contribution funded assets, this feeds through into tariff, and the consumer is being charged twice - (a) when his funds were used for creation of asset wherein he incurs losses on the time value of money, (b) when he has to pay a tariff which is higher by the amount of depreciation allowed on the asset created with his funds. This is against the principles of natural justice. In addition to this, due to the fact that depreciation is being recovered through tariff as a revenue expense and there is no corresponding repayment / RoE needed on assets created through consumer contribution, the funds so recovered accrue to the Board as excess cash. This double recovery of funds from the consumer is one of the main reasons responsible for the huge cash balances shown on the Board's balance sheet.

As the investments proposed are being separately approved by the Regulatory Commission and as it would be difficult for the Commission to monitor the depreciation amount collected towards consumer contribution and therefore, it would be appropriate to disallow depreciation on assets funded by consumers and other grants. The KSERC has taken into account this aspect in the ARR Order 2010-11.

9.2.13 Employee expenses

A few of the statements from the filings of the Board are indicative of the attitude of the Board to the issue of stringent cost controls and driving efficiency in operations. They are reproduced below for easy reference:

'DA and terminal benefits are allowed periodically in line with the policy of Government of Kerala and hence the Board cannot deny payment of such benefits. As and when the Government releases DA installments to its employees, the same are extended to the employees in the Board as well. This is in line with the wage agreement with the employees and Government policy. This practice is in vogue for the last several decades. With a view to improve operating efficiency and timely service, the number of employees has to be increased in proportion to the number of consumers. The commission may be well aware that in recruitment, payment of remuneration etc. the system in the Board is very transparent and is totally in line with Government Policy.'

The Board claims that it has to continue practices because they have been in vogue for several decades. This shows KSEB is unaware of the changes that have been sweeping across the country as a whole and the electricity sector in particular. In several states, once monolithic, inefficient SEBs, have been unbundled. Generation, transmission & distribution have been thrown open to private participation since the governments of the country will be unable to fund the massive expansion in capacity needed in generation, transmission and distribution to support the economic growth and progress of the country. All these happened though they had not been in vogue for several decades.

The Commission had earlier expressed its concern over Board's irrational approach towards projection of employee expense in various ARR and ERC orders. The Commissions observations in previous Orders in this regard are reproduced below:

"The share of employee cost in the ARR is an area of concern. The Commission in its previous Orders had raised this issue in unequivocal terms. As stated in the previous Order, the Board may review and critically evaluate innovative and acceptable alternative options to mitigate the liabilities and burden of terminal benefits, such as transition to a funded system of pension payments for new employees and senior level executives and a system of incentives to encourage migration of existing employees to funded systems".

"The Board has not submitted any material on employee productivity and functional deployment of existing and proposed manpower as well as human resource policies to achieve the Standards of Performance stipulated by the Commission and other regulatory measures envisaged in the Act and Policies. The Commission refers to the directives in the previous Orders that an in-house team of the Board may identify the scope for methods of improvement, rationalization of manpower etc. aiming at enhanced employee productivity"

"The Commission is of the view that the Board has to attempt in addressing the employee cost on the above lines and apprise the Commission."

Needless to say, these directives of the KSERC are yet to be complied by KSEB.

9.2.14 Reduction in penal charges

KSERC as per regulations has reduced penal interest on belated payment of consumers from 24% to 12%. This has imparted great relief to consumers.

9.2.15 Interest for cash security

Board has been collecting cash deposits from consumers for giving new connection. Commission has issued orders to KSEB and other licensees to pay interest at Bank rates to consumers for the deposits.

9.2.16 Transparent process of decision making

The Commission organizes Public Hearings on all matters for presenting facts & grievances of the public and other stakeholders in various parts of the State to reach a vide spectrum of the population. Further the public can submit written opinion on tariff and other matters. Commission finalizes its Orders through this transparent process. Thus the Commission through its concerted efforts could instill confidence in the minds of the stake holders and the general public as a judicial body imbibing the true spirit of the Electricity Act, 2003.

In this context, it may be noted that during the pre-regulatory period electricity tariff was fixed by KSEB with the permission of Government. KSEB or Government before effecting such abnormal upward revisions in tariff did not study the impact of tariff hike on the industrial consumers, especially power intensive manufacturing units. As a result, a number power intensive manufacturing units became economically unviable and ultimately wound up. For example, Indian Alumium Company Limited, Alupuram Works, India's first primary aluminium smelter and the single largest consumer of electricity in the state right from its inception in 1943 became economically unviable due to spiraling increase in cost of production on account of frequent tariff hike and ultimately wound up its smelting operations in August 2003.

9.2.17 Open Access Order.

Commission has issued an order on open access in the year 2004 which was the first order on open access in the country. This order was issued to Indian Aluminium Company Ltd to wheel 30 MW power from outside the state through KSEB's transmission lines as mentioned in Chapter – VII. This order of the commission is attached as Annexure – III.

9.2.18 Appointment of Ombudsman and Formation of CGRF

For addressing consumer complaints, 3 Nos. of Consumer Grievance Redressal Forums have been constituted under KSEB and one each under other Licensees with two members from the licensee one member from the public appointed by the Commission. Also an Ombudsman has been appointed by the Commission at Kochi for dealing with appeals of consumers not satisfied by the decisions of CGRF. The Ombudsman has been giving considerable relief to consumers in the settlement of claims.

9.2.19 Services

1. Compliance Examiner: A Compliance Examiner has been posted by Kerala State Electricity Regulatory Commission for conducting field verification throughout the Kerala State to see whether the Electricity Act and Regulations issued by the Commission are complied with by the KSEB and Licensees. Any violations carrying difficulties to consumers are corrected by exercising the penal provisions of Electricity Act.
2. A Consumer Advocacy Cell has been constituted in the Office of KSERC under the leadership of the Compliance Examiner. Their duties and functions are

    1. To empower consumers to participate effectively in the regulatory process
    2. To represent consumers on all matters relating to power sector
    3. To act as a clearing house of information to consumers on electricity issues
    4. To arrange workshops and training programmes for consumer advocacy groups
    5. To publish newsletters, fact sheets and other informative materials
    6. To interact with the media
    7. To conduct survey and publish reports
    8. To recommend to the KERC on matters relating to consumer protection

9.2.20 Performance Standards for Licensees in the State

KSERC has issued Standards of Performance Regulation for Distribution in the year 2006 in which compensation for non-compliance of this regulation is also stipulated. Rates of compensation specified in the regulation are given in Table 9.7.

Table – 9.7

Standards of Performance and Amount to be paid to Consumers for Default in Each case

Nature of Service	**Standards of Performance (Indicative Maximum time limit for rendering service)**	**Amount payable to affected consumer**
1. Normal Fuse-off Call		
Cities and Towns	Within 6 hrs of recording of complaints with licensee	Rs.25 in each case of default
Rural areas	Within 24 hrs of recording of complaints with the licensee	Rs.25 in each case of default
2. Line Breakdowns		
Cities and Towns	Within 12 hrs	Rs.25 to each affected consumer
Rural areas	Within 24 hrs in all cases	Rs.25 to each affected consumer
3.Distribution Transformer Failure		
Cities and Towns	Within 24 hrs of reporting of failure of transformers	Rs.25 to each affected consumer
Rural areas	Within 48 hrs of reporting of failure of transformers	Rs.25 to each affected consumer
4. Period of Scheduled Outages		
Maximum duration in a single stretch	Not to exceed 12 hrs	Rs.25 to each affected consumer
Restoration of supply	By 6 PM on any day	Rs.25 to each affected consumer
5.Meter Complaints		
Inspect and check correctness	Within 30 days	Rs.10 in each case of default
Replace slow, creeping or stuck metes	Within 30 days	Rs.10 in each case of default
Replace burnt meters if cause no attributable to consumer	Within 7 days of receipt of complaint	Rs. 10 in each case of default
Replace burnt meters in all other cases	Within 24 hrs of payment of charges by consumer	Rs.10 in each case of default

6. Application for new connection/additional load		
Release of supply where service is feasible from existing line without system Deviation. (Weatherproof connection only)	Within one month of receipt of application in complete shape and remittance of CD & connection charges. As per Supply Code	Rs.50 for each day of default
Release of supply where, extension of line, Network expansion/ enhancement required for providing connection	As specified by the Commission in the Kerala Electricity Supply Code, 2005	Rs.50 for each day of default in case of LT and Rs.50 for each day of default in case of HT.
7. Erection of substation for release of supply	As specified by the Commission in the Kerala Electricity Supply Code, 2005. This will be applicable in the case of applicants who have remitted cost as per Section 46 of the Electricity Act.	Rs.100 for each day of default.
8. Transfer of ownership and Change of category	Within 14 days of receipt of application in complete shape	Rs.50 for each day of default
9. Conversion of LT single phase to LT three phase service connection	Within 30 days from the date of payment of charges if no additional line or substation is involved	Rs.50 for each day of default
10.Conversion from LT to HT if HT line is involved, if transformer substation is involved	As per Kerala Electricity Supply Code 2005	Rs. 50 for each day of default
11.Resolution of complaints on consumers' Bills if no additional information is required	Within 24 hrs of receipt of complaint	Rs.25 for each day of default
If additional information is required	Within 7 days of receipt of complaint	Rs.25 for each day of default

12. Reconnection of supply following disconnection		
Towns and cities	On the same day	Rs.50 for each day of default
Rural areas	Within 24 hrs of receipt of payment from consumer	Rs. 50 for each day of default
13. Payment of Exgratia in case of electric accidents		
Cases where it is established beyond doubt that the accident is not due to the fault of the victim	Within 30 days without waiting for the report from CEIG	Rs.50 for each day of default
In other cases	Within 30 days after receipt of report from CEIG	Rs.50 for each day of default
14.Refund of Deposits	Within 60 days after receipt of request and deposit receipt	Rs.50 for each day of delay

Source: KSERC, Thiruvananthapuram

9.2.21 Non-compliance to Multi Year Tariff framework regulations

While filing tariff petitions, the KSEB used to make a declaration that tariff application has been prepared as per the terms and conditions for determination of tariff under section -61 of the Electricity Act, 2003 and the terms and conditions of the KSERC (Tariff) Regulations, 2003 issued by the Commission. Further, the relevant provisions of Indian Electricity Act 1910, Electricity (Supply) Act, 1948 and Electricity Regulatory Commission Act, 1998 which are not contradictory to the Electricity Act 2003, are also claimed to have been taken into consideration while preparing this petition. But section 61(f) mandates that in specifying the terms and conditions of tariff, the Regulatory Commission is required to adopt the principles of multi-year tariff determination. The relevant extract from the Act is reproduced below for easy reference

"61. The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely (f) multi year tariff principles;"

Further, the National Electricity Policy 2005 states that the MYT framework is an important structural incentive framework, to minimise risks for all stakeholders and drive improvements in system losses and operational efficiencies. The relevant portion of NEP 2005 is given below:

"5.4.4 Conducive business environment in terms of adequate returns and suitable transitional model with predetermined improvements in efficiency parameters in distribution business would be necessary for facilitating funding and attracting investments in distribution. Multi-Year Tariff (MYT) framework is an important structural incentive to minimize risks for utilities and consumers, promote efficiency and rapid reduction of system losses. It would serve public interest through economic efficiency and improved service quality. It would also bring greater predictability to consumer tariffs by restricting tariff adjustments to known indicators such as power purchase prices and inflation indices. Private sector participation in distribution needs to be encouraged for achieving the requisite reduction in transmission and distribution losses and improving the quality of service to the consumers."

Similarly, Section 5.3 (h) of the National Tariff Policy 2006 deals with the issue of MYT framework

h) Multiyear Tariff –

1) Section 61 of the Act 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 principles. The MYT framework is to be adopted for any tariffs to be determined from April 1, 2006. The framework should feature a five-year control period. The initial control period may however be of 3 year duration for transmission and *distribution if deemed necessary by the Regulatory Commission on account of data uncertainties and other practical considerations. In cases of lack of reliable data, the Appropriate Commission may state assumptions in MYT for first control period and a fresh control period may be started as and when more reliable data becomes available.*

5*) Clear guidelines and regulations on information disclosure may be developed by the Regulatory Commissions. Section 62 (2) of the Act empowers the Appropriate Commission to require licensees to furnish separate details, as may be specified in respect of generation, transmission and distribution for determination of tariff.*

Section 8.1 of the National Tariff Policy deals specifically with MYT framework implementation in distribution, and relevant sections are reproduced below:

Implementation of Multi-Year Tariff (MYT) framework

1) This would minimise risks for utilities and consumers, promote efficiency and appropriate reduction of system losses and attract investments and would also bring greater predictability to consumer tariffs on the whole by restricting tariff adjustments to known indicators on power purchase prices and inflation indices. The framework should be applied for both public and private utilities.

7) *Appropriate Commissions should initiate tariff determination and regulatory scrutiny on a suo-moto basis in case the licensee does not initiate filings in time. It is desirable that requisite tariff changes come into effect from the date of commencement of each financial year and any gap on account of delay in filing should be on account of licensee.*

As per Section 61(f) of the Electricity Act, and provisions of the NEP05 & NTP06, the Commission has issued the KSERC (Terms and Conditions of Tariff for

Distribution & Retail sale of Electricity under Multi Year Tariff Framework) Regulations 2006 on 12th October 2006. The regulations require the licensee to file for ARR for a period of three years, which is the first control period, starting from FY07–08.

In Chapter XI – Directives, Section 11.1 of the ARR and ERC Order for the year FY2007-08, the Commission has given the following directive to the Board:

"The Commission in accordance with the provisions of Sub Sections (2) and (5) of Section 62 of the Act and Section 86(1) (a) thereof, is mandated to determine separate tariff for generation, supply, transmission, distribution, wheeling and retail sale of electricity within the State irrespective of the fact that whether the State utility has remained vertically integrated or has been unbundled. The statute does not make any distinction between a licensee and a deemed licensee; and same procedure shall be applicable for determination of tariff for transmission and distribution of electricity to new licensees as well as the deemed licensees"

Also, reference is made to the Section 5.3(h) of the Tariff Policy wherein it is stated that the MYT framework has to be adopted for tariff determination in future.

"The forum of Regulators has considered the time requirement of data collection for the preparation of MYT and decided that filing under MYT regime might be commenced from the base year of FY2008-09. Therefore, in line with these requirements, the Board shall submit a detailed Multi Year Tariff petition from FY 2008-09 with complete supporting data and analysis in accordance with the relevant sections/ provisions of Electricity Act 2003 and Tariff Policy"

Since the issuance of the ARR & ERC Order for FY07-08, directing filing under MYT framework from FY08-09 onwards, the Board has filed ARR & ERC applications for approval to the Commission for FY08-09, FY09-10 and FY10-11 on an annual basis. Therefore, KSEB has not complied with the provisions of the Act, the NEP05, the NTP06, applicable regulations and lawful directives of KSERC, which is in violation of the existing legal, policy & regulatory regime in the country.

However, KSERC has continued to accept the Board's filings without dissent on this crucial non-compliance, which in turn would encourage KSEB to default on its regulatory obligations, and flout the authority and power of the Commission with impunity. The Board was wilfully refusing to comply with regulations that it is legally bound to follow, since it is under the impression that the Commission will allow business as usual to continue.

The idea behind the multi-year tariff regime is to provide certainty to consumers regarding tariffs for electricity over an extended period of time, to have a clear path defined with measurable milestones to guide the process of reforms in the electricity sector and to provide certainty to the licensee with regards to its costs and revenue. By refusing to follow the MYT regulations, the Board is actually holding up the progress of the electricity sector reforms in the state, as this allows it to continue with business as usual of inflated costs foisted onto hapless consumers, and this situation need to be changed. MYT framework is an incentive framework which motivates the licensee to reduce losses and improve efficiencies. Any delay in the filing of multiyear tariffs will completely be against the principles of efficiency. The States which are already implemented Multi-year tariff structure are listed in Table 9.8.

Table 9.8

List of states that file for ARR & ERC under the MYT framework

States
Maharashtra
Andhra Pradesh
Madhya Pradesh
Orissa
Karnataka
Himachal Pradesh
Delhi
West Bengal
Rajasthan
Gujarat
Assam

Source: Central Electricity Regulatory Commission, Delhi

9.2.22 Violation of timelines for submission of Application for ARR and ERC filing

Section 3 (1) of the KSERC (Tariff) Regulations, 2003 clearly specifies the timeline for submission:

November 30th of each year is the cut off date for filing of ARR & ERC application along with appropriate tariff proposal. The date of filings for previous years, starting from FY-05, reveals that the violation on compliance to timelines has occurred in every year except FY-06 and FY-07. The list of actual submission dates from FY-05 is given below:

Table 9.9

Dates of the Submission of Applications for approval of ARR and ERC

FY	Date of Submission
FY 04-05	15.12.03
FY 05-06	15.11.04
FY06-07	30.11.05
FY07-08	11.12.06
FY08-09	21.12.07
FY09-10	29.12.08
FY10-11	24.12.09

Source: KSERC, Thiruvananthapuram

9.2.23 Regulations issued by the Commission

The Commission has issued 37 Nos. of regulations with an intention to strengthen the process of regulatory governance in Kerala’s power sector. The regulations are listed in Annexure - II.

9.2.24 Segregation of Accounts for Generation, Transmission, Distribution and Supply

The unbundling of vertically integrated utilities in the country into the distinct functions of generation, transmission and distribution is called for in the Electricity Act 2003. The reason for this is that these three functional areas are distinct in the electricity supply activity chain, and each calls for a different set of competencies, which when developed will ensure efficient and effective operations leading to quality of service improvements, identification of areas of deficiency and focused activity to drive efficiency gains resulting in benefits to consumers and sustainable, profitable operations of the utilities. The Commission has directed the Board to provide segregated accounts for each function of the Board to enable the Commission to determine separate tariffs for each business. However, the Board has repeatedly failed to provide the details. The directive of the Commission as per the ARR and ERC order for FY07-08 is as shown below:

'The Commission in accordance with the provisions of Sub Sections (2) and (5) of Section 62 of the Act and Section 86(1) (a) thereof, is mandated to determine separate tariff for generation, supply, transmission, distribution, wheeling and retail sale of electricity within the State irrespective of the fact that whether the State utility has remained vertically integrated or has been unbundled. The statute does not make any distinction between a licensee and a deemed licensee; the same procedure shall be applicable for determination of tariff for transmission and distribution of electricity to new licensees as well as the deemed licensees.'

The Commission has repeated its direction to the KSEB to initiate the process of segregation of the accounts for each function in its Order dated August 27, 2009 in response to KSEB's Review Petition on May 27, 2009 on the ARR and ERC Order for FY09-10. The relevant extract from the Order is *"Hence, by accepting the suggestion of KSEB for fixing norms for various items, the Commission hereby directs that a proposal for fixing norms for generation, transmission and distribution* *separately shall be filed by KSEB within two months, with all supporting details including past 10 years function level expenses and performance.”*

The regulations of the Commission also call for segregation of ARR between distribution and supply, to ensure transparency in the functioning of the Board and ensure that efficiency targets are met in each functional area of the Board. Naturally, the Board with its vested interest in maintaining status quo to avoid scrutiny of its operations, which allows it the freedom to inflate costs at will, has failed to comply with this directive as well. The Board has failed to comply with the two-months timeline, and has refused to provide segregated costs. After inordinate delay, the Government has initiated the first steps towards corporatisation of the Board. The Board in its filing for FY09-10 had stated that “Government of Kerala as per Section 131 of the Electricity Act, 2003 has vide Order No.MS 37/2008/PD dated 25-10-2008, had issued orders for vesting all the functions, properties, interests, rights, obligations and liabilities of KSEB which will be revested to a new entity within one year ie., by September 2009.” KSEB in its ARR&ERC petition for 2010-11,the same lines have been repeated, but it is interesting to note that no timeline has been specified for completion of the process, reflecting the attitude the Board to fight change at any cost. The unbundling of KSEB would obviously lead to segregation of accounts, which is necessary to target efficiency measures at each functional level. It can be seen from Commission’s observations that unbundling is being deliberately delayed by the Board to avoid segregation of accounts and exposure of inefficiencies in operations. Further, the Government would like to continue its practice of mandating subsidies for certain categories of consumers, whilst continuing to shirk its responsibility of bearing the cost of such subsidies, as mandated in the Act, and the Board would not like do ununbundling as it would throw more light on its inefficiencies.

9.2.25 Cross Subsidy

As per Section 61 of the Electricity Act, the State Electricity Regulatory Commission has to be guided by the principles enumerated in the said section in determining terms and conditions of tariff. The National Tariff Policy requires the State Commissions to reduce cross subsidies and bring down tariffs within the levels of ±20% of the average cost of supply by year 2010-2011. And as per Section-19 of the KSERC (Terms and Conditions of Tariff for Retail Sale of Electricity) Regulations, 2006 *"A road map for cross subsidy reduction will be fixed by the Commission and will be reviewed on the basis of average cost of supply"*. Till date the KSEB has submitted no proposal towards the same, as reduction in cross subsidy, in the absence of Government subsidy support, will necessarily raise tariffs, leading to a firestorm of protest against the inefficient operations of the Board, which will force the change which the Board has been resisting all along. There is also an important observation made by the Hon'ble Appellate Tribunal of Electricity (ATE) in Appeal No. 131 of 2005

"On consideration of the submissions of the learned counsel for the Appellant and Respondents, the provisions of the Electricity Act 2003, the National Electricity and Tariff Policies, we are of the view that the cross-subsides can only be gradually reduced and brought to the levels envisaged by the Act and the Tariff Policy."

From the above reading of the Tribunal order, it is evident that the cross-subsidies can only be reduced and the Commission should ensure reduction of cross-subsidies. The Tribunal's order further states that *"there is an urgent need for ensuring recovery of cost of service from consumers to make the power sector sustainable"*. Thus, the Commission ensure category-wise CoS (Cost of Supply) determination and fix tariffs to recover costs based on this.

Tamil Nadu ERC Tariff Order dated 15-03-2003 in section 7.5 Cross-subsidy Reduction says:

"The Commission is committed to gradually reduce the cross-subsidies in the State over a five-year period, by increasing the tariffs applicable to the subsidised categories, viz. agriculture, domestic, Lift Irrigation Societies, power looms and Cottage industries, and reducing the tariffs applicable to the subsidising categories, viz. HT and LT industrial consumers, Railway Traction, HT and LT Commercial

category, etc. However, the magnitude of the tariff revision required and the level of cross-subsidy is such that the Commission has been compelled to increase the tariffs for the subsidising categories also, in order to avoid tariff shock for the subsidised categories. The Commission has endeavoured to minimise the tariff increase for the subsidising categories while undertaking higher tariff increases for the subsidised categories"

In this order, in line with the decision of the Commission as above, Tariff increase for HT Industry was 6.69% and for total HT Category it was 7.14% only where as for Domestic Category the increase was 22.13% and for total LT Category it was 19.30%. This clearly shows that TNERC rationalized tariffs by reducing cross-subsidies in line with Electricity Act 2003.

Also on the requirement of category-wise and voltage-wise cost of supply, the Hon'ble ATE in its order in Appeal Nos. 4, 13, 14, 23, 25, 26, 35, 36, 54 & 55 of 2005, dated 26th May 2006, Punjab Industries Vs Punjab State Electricity Regulatory Commission:

"110. Keeping in view the provisions of Section 61 (g), which requires tariff to ultimately reflect the cost of supply of electricity and the National Tariff Policy, which requires tariff to be within +- 20% of the average cost of supply, it seems to us that the Commission must determine the cost of supply, as that is the goal set by the Act. It should also determine the average cost of supply. Once the figures are known, they must be juxtaposed, with the actual tariff fixed by the commission. This will transparently show the extent of cross subsidy added to the tariff, which will be the difference between the tariff per unit and the actual cost of supply."

On the above grounds the Commission to clearly specify cross subsidy reduction plan and targets, determine category or voltage-wise cost of service and ensure cross subsidy reduction plan targets and consumer category wise cost recovery. The average cost of supply is only an intermediate target as it cannot be inconsistent with the Act. In case, where tariffs are already reflecting average cost of supply targets, the KSERC need to focus on the principles of the Act i.e. moving towards category-wise / voltage-wise cost of supply.

9.2.26 Subsidy

Section-65 of the Electricity Act states that the State Government can choose to subsidise the consumption of a consumer or category of consumers. However, it also lays the responsibility of funding the cost of that subsidy on the State Government. The relevant extracts are reproduced below:

'If the State Government requires the grant of any subsidy to any consumer or class of consumers in the tariff determined by the State Commission under section 62, the State Government shall, notwithstanding any direction which may be given under section 108, pay, within in advance in the manner as may be specified , by the State Commission the amount to compensate the person affected by the grant of subsidy in the manner the State Commission may direct, as a condition for the license or any other person concerned to implement the subsidy provided for by the State Government :

Provided that no such direction of the State Government shall be operative if the payment is not made in accordance with the provisions contained in this section and the tariff fixed by State Commission shall be applicable from the date of issue of orders by the Commission in this regard"'

It is clear from a reading of Section 65 of the Act that, to implement the decision of the Government to subsidise consumption, the Government has to release the committed subsidy to the Board, in advance.

The Board has stated that it has been providing subsidised electricity, even in the absence of such advance payment of amounts required to implement the subsidy decision of the GoK, which has resulted in the need for "heavy borrowings to meet the expenses". This is in fact is in violation of Section 65 of the Act.

The extract from the National Tariff Policy 2006 is instructive on the modality of implementation of subsidy decisions of the Government, if any. Relevant sections of NTP-2006 are reproduced below :

"8.2.1 (3) Section 65 of the Act provides that no direction of the State Government regarding grant of subsidy to consumers in the tariff determined by the State Commission shall be operative if the payment on account of subsidy as decided by the State Commission is not made to the utilities and the tariff fixed by the State Commission shall be applicable from the date of issue of orders by the Commission in this regard. The State Commissions should ensure compliance of this provision of law to ensure financial viability of the utilities. To ensure implementation of the provision of the law, the State Commission should determine the tariff initially, without considering the subsidy commitment by the State Government and subsidised tariff shall be arrived at thereafter considering the subsidy by the State Government for the respective categories of consumers."

This indicates that there is a requirement for two sets of tariffs. One would be as determined by the Commission as per the guiding factors given in section 61 of the Electricity Act - 2003 and would ensure full recovery of cost by the licensee in the absence of any subsidy decision by the Government. The second set of tariffs would be determined after factoring in the policy decision of the Government regarding provision of subsidies to relevant categories of consumers and the quantum of such subsidy.

These two set of tariffs would enable the Regulatory Commission to be in compliance with the directive of the NTP 2006, requiring SERCs to ensure compliance to separation of subsidy and cross subsidy, and implementation of subsidy only if subsidy amounts due are paid in advance, as directed by the State Regulatory Commission. Thus KSERC to determine the "Commission Determined Tariff" which should meet approved aggregate revenue requirement without government subsidy, and if and when government subsidy is received, in advance, alternate Retail Supply Tariff may be implemented.

9.2.27 Regulatory Asset

In the Application for approval of the ARR and ERC for the FY10-11 KSEB has requested KSERC to recognize the concept of Regulatory Asset and treat the revenue gaps as Regulatory Asset, if the gaps are not otherwise covered by tariff revision or subsidy from the Government.

The relevant extracts from KSERC (Terms and Conditions of Tariff for Retail Sale of Electricity) Regulations, 2006 are:

"18. Regulatory Asset. –

(1) The Commission shall, at its discretion, provide for regulatory asset by specifying the amortization and financing rules of the regulatory assets submitted by the licensees and adopted by the Commission.

(2) Regulatory assets shall be allowed at the discretion of Commission and allowed to take care of force-majeure or cost variations due to uncontrollable factors.

(3) Financing cost of regulatory asset shall be allowed to the licensees.

(4) *Recovery of regulatory assets should be time bound and within a period normally not exceeding 3 years"*

These principles are laid out in the NTP 2006 as well as reproduced below:

"8.2.2. The facility of a regulatory asset has been adopted by some Regulatory Commissions in the past to limit tariff impact in a particular year. This should be done only as exception, and subject to the following guidelines:

a) The circumstances should be clearly defined through regulations, and should only include natural causes or force majeure conditions. Under business as usual conditions, the opening balances of uncovered gap must be covered through transition financing arrangement or capital restructuring;

b) Carrying cost of Regulatory Asset should be allowed to the utilities;

c) Recovery of Regulatory Asset should be time-bound and within a period not exceeding three years at the most and preferably within control period;

d) The use of the facility of Regulatory Asset should not be repetitive.

e) In cases where regulatory asset is proposed to be adopted, it should be ensured that the return on equity should not become unreasonably low in any year so that the capability of the licensee to borrow is not adversely affected.

It is pertinent to point out that the concept of a regulatory asset has been introduced to handle cost variations due to uncontrollable factors and thus prevent a tariff shock to consumers. In the present situation in Kerala, where the Board is showing revenue gaps year after year, leading to gaps running into thousands of Crores of rupees, it is hard to foresee a situation in the near future where the Board will show revenue surpluses to offset the impact of amortization of the regulatory asset as per the regulations of the Commission. This is just postponing the day of reckoning and storing up problems for later, at which point in time, it will be much harder to tackle the issue.

However, KSERC did not allow creation of regulatory asset during the above mentioned ARR & ERC approval for 2010-11

9.2.28 Revised filings for FY2009-10

The Board repeatedly filed the revised estimates for ARR and ERC of the previous year as part of the filing for the current year, which is not maintainable. This should be done as part of an annual true up exercise only, as has been provided for in applicable regulations. This is the practice followed by utilities and Commissions in other states. The State Commission, by allowing the Board to continue with this practice of filing revised estimates for previous years, as part of the filing of ARR & ERC for the ensuing year, is allowing unnecessary complexity and confusion to creep into the whole electricity sector reforms process of the state. It must be pointed out that this serves the sole intent of the Board - to delay the process of reforms as long as possible.

The Board has requested, and the Commission has conducted true-up for FY03-04, FY04-05 and FY05-06. Further, the true-up petition for FY06-07 is presently before this Hon'ble Commission for its consideration. This is sufficient mechanism for the Board to recover any gaps or return the surpluses that it has earned in previous years. The delays in the true-ups in the State are on account of unnecessary delays by the Board itself in filing true-up petitions. For example, the Petition on Truing-up of Cost and Revenue for FY06-07 has been filed only in 2010. There is sufficient reason to suspect that the delay is intentional to avoid returning the surpluses that it has earned in previous years to consumers. The huge cash & bank balances shown in the balance sheet of the Board is an indicator of this fact.

9.2.29 Continued non-compliance to Commission Orders

Category-wise CoS study - The Commission has been repeatedly directing the Board to conduct appropriate studies to determine consumer category-wise CoS (Cost of Supply). However, the Board has not undertaken any such study.

Capital expenditure - The regulations applicable state that the Board has to file detailed capital expenditure plans for the approval of the Commission. However, the Board has repeatedly failed to file Capex plans detailing timelines, expenditure, cost benefit analysis etc. The directives of the Commission's Order for FY09-10 specified that the Board should have prepared an implementation plan including procurement plan for all the important capital projects under generation, transmission and distribution with information to the Commission. No plan or any detailed description of the capital projects was submitted till date. The chapter on Capital Investments of the Application for the approval of the ARR and ERC for the FY10-11 doesn't contain description of the major generation /transmission/ distribution projects.

As per the KSERC Order for FY09-10 separation of Transmission and Distribution Losses should be performed by the Board - In the KSERC Order for FY09-10 the Board was directed to initiate a study for assessing loss levels in 33kV/11kV system and LT system separately. The study was initiated, however, the

Board did not come up with preliminary results within the timeframe specified in the Order and put forward its own timelines, claiming that its interface meters are inaccurate. The Commission had directed the Board to provide separate estimates of transmission and distribution losses at different voltage levels with the ARR and ERC filing for subsequent years. In the filing for FY10-11 there are no estimates provided separately for transmission and distribution losses, but stated that the exercise failed due to various technical reasons. The KSERC (Tariff) Regulations 2003, notified in January 2004, itself lays out the need for provide losses separately. Now the Board claims that it is unable to provide voltage-wise losses.

Board has not complied with repeated directives of the Hon'ble Commission on crucial points and that the Hon'ble Commission has condoned these non-compliances of the Board (Refer Annexure-V).

9.3 Suggestions

Even though the intervention of Regulatory Commission is strongly felt in Kerala's power sector and KSEB started showing visible improvements in its financial and operating performance, certain key objectives of the power sector reforms Act viz. Electricity Act-2003, National Electricity Policy-2005 and National Tariff Policy-2006 are not yet complied with by the KSEB. The tendency of the licensee to evade from the directives of SERC is evident in many cases.

Following are the main suggestions to ensure reform, deregulation and restructuring of power sector as envisaged in the preamble of Electricity Act 2003, which is regarded as the driving force of regulatory regime.

1. KSEB has to do unbundling of generation, transmission and distribution and separate accounts for each function as per the provisions of the Electricity Act-2003.

2. KSEB to file proposals for Multi-Year Tariff (MYT) without further delay.

3. Rationalization of power tariff on the basis of “Actual Cost of Supply” or “Cost to Serve Model” for different voltage category of consumers to reflect actual cost and to eliminate cross subsidy in a phased manner

4. KSEB to submit time bound action plans for eliminating cross subsidy in a phased manner and comply with the orders of KSERC in reducing / eliminating cross subsidy.

5. Separation of Transmission & Distribution losses to be done by KSEB

6. Separation of Technical and Commercial losses to be done by KSEB

7. Violation of time limits in submitting application for ARR & ERC and Truing up of ARR& ERC to be avoided.

8. Compliance to the directives issued by KSERC from time to time.

9. KSEB to study the socio-economic impact of closure of power intensive industries (like the Smelter Unit of Indian Aluminium Company Limited, which was KSEB’s largest consumer of power till its) consumers in the state during pre-regulatory regime to determine direct and indirect loss of revenue to the KSEB in particular and the State in general and initiate appropriate steps to bring such industrial consumers back to KSEB’s fold.

9.4 Conclusions

Electricity is an essential requirement for all facets of our life. It has been recognized as a basic human need. It is a critical infrastructure on which the socio-economic development of the country depends. Industrial growth in Kerala State, especially in the manufacturing sector is quite dismal over the last 20 years. Growth of manufacturing industries is one of the major contributing factors for economic growth, generation of direct and indirect employment opportunities. The socioeconomic development of various regions within the State is directly linked to the Industrial growth and development of those regions. It will accelerate the overall economic development of the State including power sector.

Through various ARR & ERC Orders the KSERC has reminded KSEB about its inherent obligation and duty to optimally plan, develop and maintain the electricity system in the most reasonable and efficient manner. KSEB has been consistently projecting expenses more than what is optimally required for efficient services. On several occasions, KSERC in principle disagreed with KSEB's practice of projecting high level of expenditure, without any proposals or attempts to plan and control the expenses. Commission opined on several occasions that 'Cost plus regulatory regime' is not about passing on all costs incurred by the utilities, but about prudently optimal and efficiently managed costs being loaded on to the consumers. The KSERC was forced to exercise its regulatory scrutiny to optimize, control and prune certain expenses during the reviews of KSEB's petitions on ARR&ERC in the past. In reality, KSEB has failed to control the expenses at the approved level, notably in areas where restraints have to be observed such as many items of revenue expenditure, and reduced the expenditure much below the desired level in areas where it was very much needed such as capital expenditure. The Kerala Regulatory Commission is doing an excellent prudence check of KSEB's tariff petitions with the involvement of all stakeholders by conducting public hearings and thus making the process of approval of ARR&ERC more meaningful.

There is a visible change in the performance of power sector consequent to the establishment of KSERC. The tariff rates are almost stable and there was no hike in the tariff of Industrial Consumers for the last nine years (ie after the setting up of KSERC). Arresting the steep increase in the electricity tariff which was in vogue for a decade and maintaining it at the same level for almost another decade is the single largest achievement of Kerala State Electricity Regulatory Commission. This is a silver line in the history of Kerala Power Sector. This is not properly realized and appreciated by the public and media.

KSEB has shown a lot of reluctance in complying with the directives of KSERC during the initial years of regulatory regime as it was a monopoly public sector utility under the control of Government and its decisions were mostly based on political compulsions rather than operating efficiencies and cost. Now KSEB started realizing the fact that KSERC is a reality and there is no shortcut to escape from the reforms taking place in the country in which the role of power sector is vital. However, more awareness needs to be created among the stakeholders, especially all sections of electricity consumers to enhance the level of participation and involvement in the regulatory process. More awareness needs to be created among the public on the conservation, economic use and actual voltage category-wise cost of electricity.

Besides maintaining a stable industrial electricity tariff, the Commission could achieve improvements in the areas of T & D lose reduction quality of power generation and purchase in the order of merit and consumer grievance Redressal as mentioned in the findings. However the areas where KSERC could not achieve much progress are, multi-year tariff, reduction in employment cost, open access regulations to improve power trading in the State, cross subsidy reduction etc. But, we can conclude that the overall functioning of KSERC has been a grand success.

A vibrant power sector will ensure industrial growth in the state which in turn will result in the growth and development of the state in general and power sector in particular on account of the fact that even today Industrial Electricity consumers, who consume about 28% of the total energy sales to consumers by the Kerala State Electricity Board contribute about 37% to the total revenue from tariffs. Similarly, services sector has made significant contribution to the growth of our State. Availability and affordability of quality supply of electricity is very crucial to sustained growth of this segment also. As observed by the Regulatory Commission in the open access order issued to INDAL "**it is impossible to sustain power development without industrial development".**

BIBLIOGRAPHY

1. A. Kish, IHS Global Insight, Inc., '*Quarterly Review and Outlook First Quarter 2010: United States, Canada, and Eurozone'* (Lexington, MA, March 2010), p. 16.
2. Agarwal O P and P Paul. 2001*, 'Framework for Independent Regulation in India: an overview'* In Regulation in Infrastructure Services: Progress and the Way Forward, edited by S K Sarkar and Kaushik Deb New Delhi: Tata Energy Research Institute
3. Alexander, Ian (2003), '*UK Model on Developing and Transition Economies: Common Issues and Misconceptions',* South Asia Energy and Infrastructure Unit, World Bank, Washington DC, http ://info.worldbank.org/ etools/docs/library/86469/ ses2.1_ ukmodelondeveloping.pdf
4. Averch.H and Johnson L *'The Behaviour of the Firm Under Regulatory Constraint,'* American Economic Review, December 1962
5. B. Neff, IHS Global Insight, '*Quarterly Review and Outlook: Asia-Pacific'* (Lexington, MA, March 2010), pp. 1 and 109.
6. Baijal P. 199*, 'Restructuring Power Sector in India: a base paper'* Economic and Political Weekly (25 September 1999)
7. Bakovic T, Tenenbaum B, and Woolf F. 2003, '*Regulation by Contract: a new way to privatize electricity distribution'?* Washington, DC: The World Bank Group's Mining Sector Board
8. Basu D D. 1998 *, 'Administrative law'* (5th edn)Calcutta: Kamal Law House
9. *'Belgium Postpones Nuclear Phase-Out', -* World Nuclear News (October 13, 2009), web site www. nuclear-news.org; and *'Germany's New Government May Extend Reactor Lifetime'* - Spiegel Online (September 29, 2009), web site www.spiegel.de.
10. *'China Updates Spending Details of Stimulus Fund,'* Xinhua News Agency (May 21, 2009), website http://news.xinhuanet.com/english/2009-05/21/ content_11415559.htm.

11. D. Ryan, IHS Global Insight, '*Quarterly Review and Outlook: Asia-Pacific'* (Lexington, MA, March 2010), p. 79.
12. D. Ryan, IHS Global Insight, '*Quarterly Review and Outlook: Asia-Pacific'* (Lexington, MA, March 2010), p. 77.
13. D. Ryan, IHS Global Insight, '*Quarterly Review and Outlook: Asia-Pacific'* (Lexington, MA, March 2010), p. 151.
14. D. Ryan, IHS Global Insight, '*Quarterly Review and Outlook: Asia-Pacific'* (Lexington, MA, March 2010), p. 153.
15. Department of Finance Canada, '*Budget 2009: Canada's Economic Action Plan'* (Press Announcement: Ottawa, Canada, January 27, 2009), web site www.fin.gc.ca/n08/09-11-eng.asp.
16. Dokeniya, Anupama (1999) '*Re-forming the state: telecom liberalization in India, Telecommunications Policy',* 23, 105-128.
17. Edelman M. 1964, '*The Symbolic Uses of Politics'* University of Illinois Press
18. Fuchs R F. 1969 '*The new administrative state: Judicial sanction for agency self determination in the regulation of industry'* Columbia Law Review, p. 216
19. Galligan D J . 1996 *'A reader on Administrative Law',* p. 152 Oxford: Oxford University Press
20. Galligan DJ. 1996, '*A reader on administrative law', p. 108* Oxford: Oxford University Press
21. Garner J F, et al. 1985 *, 'Administrative Law'* (6th edn) London: Butterworths
22. Gilbert R L and Kahn E P (eds). 1996 '*International Comparisons of Electricity Regulation',* p. 182 Cambridge: Cambridge University Press
23. Goodnow F J. 1990, '*Politics and Administration'* New York: Macmillan
24. Grey P. 1996, '*Comparative Electricity Regulation'* Washington, DC: World Bank
25. H. Archer, IHS Global Insight, '*Eurozone—Greece: Concerns Persist Over Eurozone Despite EU's Pledge to Greece'* (February 16, 2010), web site www.ihsglobalinsight.com (subscription site).

26. Harris, Clive, John Hodges, Michael Schur, and Padmesh Shukla (2003) '*A Review of Cancelled Projects',* Note Number, 252, World Bank, Washington DC.
27. Hart H LA. 1961*, The Concept of Law, p. 202* Oxford: Oxford University Press
28. IHS Global Insight, *World Overview: First Quarter 2010* (Lexington, MA, March 2010), p. 74. *'Pulling Apart: The World's Big Economies Were All Hit by the Recession. Now the Field Is Spreading*,' The Economist (January 23, 2010), pp. 69-70.
29. IHS Global Insight, '*World Overview: First Quarter 2010'* (Lexington, MA, March 2010), pp. 71-72 and U.S. Department of State, "Background Note: Philippines," (October 2009), web site www.state.gov/r/pa/ei/bgn/2794.htm.
30. IHS Global Insight, '*World Overview: First Quarter 2010'* (Lexington, MA, March 2010), p.119.
31. IHS Global Insight, '*World Overview: First Quarter 2010'* (Lexington, MA, March 2010), pp. 102-112
32. International Energy Agency, *World Energy Outlook 2009* (Paris, France, November 2009), pp. 128 and 134. IHS Global Insight, Inc., *"A New Year, a New Direction for the Global Economy," Global Executive Summary* (Lexington, MA, January 2010), p. 1.
33. International Monetary Fund, *'IMF Revises Up Global Forecast to Near 4% for 2010,' IMF Survey Magazine: In the News* (Washington, DC, January 26, 2010), web site www.imf. org/external/ pubs/ft/survey/so/2010 /NEW012610B. htm.
34. International Monetary Fund, '*World Economic Outlook 2009'* (Washington, DC, October 2009), pp. 84-85, web site www.imf.org/external/pubs/ft/ weo/2009/02/index.htm. '*New Dangers for the World Economy' The Economist* (February 13, 2010), p. 13.
35. International Monetary Fund, *World Economic Outlook October 2009* (Washington, DC, October 2009), p. 71, web site www.imf.org/external/ pubs/ft/ weo/2009/02/index.htm; and D. Ryan, IHS Global Insight, *Quarterly Review and Outlook: Asia-Pacific* (Lexington, MA, March 2010), p. 77.

36. International Monetary Fund, '*World Economic Outlook October 2009'* (Washington, DC, October 2009), pp. 71-73, web site www.imf.org/external/pubs/ ft/weo/2009/02/index.htm.
37. International Monetary Fund, '*World Economic Outlook October 2009' 2009* (October 2009), p. 72, web site www.imf.org/external/pubs/ft/weo/2009/02/ index.htm (Washington, DC, October 2009).
38. International Monetary Fund, '*World Economic Outlook Update'* (Washington, DC, January 26, 2010), p. 1; and IHS Global Insight, '*Global Executive Summary: A New Year, a New Direction for the Global Econom'y* (Lexington, MA, January 2010), p. 1.
39. J. Carney, "The Greek Debt Crisis Was Resolved by a Confidence Game," *Business Insider: Clusterstock* (March 8, 2010), web site www.businessinsider. com.
40. J. Narasimhan, IHS Global Insight, *Quarterly Review and Outlook: Asia-Pacific: First Quarter 2010* (Lexington, MA, March 9, 2010), p. 48.
41. Jain M P, et al. 1997, *Principles of Administrative Law (4th edn)* Nagpur: Wadhwa & Co.
42. Jain, Rekha (2006) Interconnection regulation in India: Lessons for developing countries, Telecommunications Policy, 30, 183-200.
43. Joskow P. 1997 *, Restructuring, Competition and Regulatory Reform in the US Electricity Sector* Journal of Economic Perspectives 11(3): 119-138
44. K. Olsen, "Bank of Korea Keeps Interest Rate at Record Low," *Associated Press News Release* (March 11, 2010).
45. Kannan, K. P., and Pillai, N. Vijayamohanan (2001a) *'Plight of the Power Sector in India - I: Physical Performance of SEBs- II: Financial Performance of SEBs', Economic and Political Weekly*, January 13 and 20: 130 – 139, 234 – 246.
46. Kannan, K. P., and Pillai, N. Vijayamohanan (2001b) '*The Political Economy of Public Utilities: A Study of the Indian Power Sector'* Working paper No. 316, June, Centre for Development Studies, Thiruvananthapuram.

47. Know Your Power (2006) – '*A Citizens' Primer on the Electricity Sector , Prayas (Energy Group)'* , Pune
48. Rao, S.L (2004), '*Governing Power – A New institution og governance: the experience with independent regulation of electricity'.* The Energy and Resource Institute
49. Kolamkar D S. 2002 *, 'Regulation and Policy Issues for Commodity Derivatives in India'. -* Mumbai: Indira Gandhi Institute of Development Research
50. Levy, B and P.T. Spiller (1994) The Institutional Foundations of Regulatory Commitment: A Comparative Analysis of Telecommunication Regulation, *Journal of Law Economics and Organisation,* V 10, No. 2, 201-246.
51. Lewis N. 1996 *, 'Choice and the legal order: Rising above politics'* London: Butterworths
52. Lewis N. 1996*, Choice and the Legal Order: rising above politics* London: Butterwoths
53. Lipsky M. 1980, *Street Level Bureaucracy* New York: Russel Sage
54. Longley D, et al. 1996 *, Administrative justice: Central issues in UK and European administrative law* London: Cavendish Publishing Ltd
55. Longley D, et al.1996*, Administrative Justice: Central issues in UK and European*
administrative law London: Cavendish Publishing Ltd
56. Mehta, A. (2000) *Power Play: A Study of the Enron Project*, Orient Longman, New Delhi.
57. Meier K. 1979, *Politics and Bureaucracy: policy making in the fourth branch of government* North Scituate: Duxbury Press
58. Mitchell J M, et al. 1972*, Political Analysis and Public Policy: an Introduction to Political Science* New Delhi: Thomson Press India Ltd
59. Montjoy R S and Watson D J. 1995 , *A Case for Reinterpreted Dchotomy of Politics and Admnistration as a Professional Standard in Council-Manager Government* Public Administration Review 55 (3): 231-39

60. Morris, Sebastian (1996). *"Political Economy of Electric Power in India*" Economic and Political Weekly, May 18, pp. 1201-1210.
61. Morris, Sebastian, (2000). "Regulatory Strategy and Restructuring Model for Gujarat Power Sector", Economic and Political Weekly, June 3: 1915-1928.
62. Mukherji, Rahul (2004) *'Managing Competition: Politics and the Building of Independent Regulatory Institutions'*, India Review, vol 3 No.4 pp.278-305.
63. Nachmias D and Rosenbloom D H. 1978 *, 'Bureaucratic Culture: citizens and administrators in Israel'* New York: St. Martin's Press
64. Nelson B J. 1996 *, 'Public Policy and Administration: an overview in a New Handbook of Political Science*,' edited by Robert E Goodin and Hans-Dieter Klingemann Oxford: Oxford University Press
65. Newbery, David M, and M G Pollitt (1997) *'The Restructuring and Privatisation of the UK Electricity Supply-Was it Worth it?'*, Public Policy for the Private Sector, No. 124, World Bank, Washington DC.
66. Ocana C. 2003, '*Trends in the management of regulation: a comparison of energy regulators in member countries of the Organisation for Economic Co-operation and Development'* International Journal of Regulation and Governance 3 (1): 13-32
67. P. Newport, IHS Global Insight, Inc., *Quarterly Review and Outlook First Quarter 2010: United States, Canada, and Eurozone* (Lexington, MA, March 2010), p. 11.
68. P. Vieira, "Budget 2010: A Second Year of Stimulus Spending," *The National Post* (March 4, 2010), web site www.nationalpost.com).
69. Parker, D, Kirkpatrick, C. (2005) Privatisation in developing countries: a review of the evidence and the policy lessons, *Journal of Development Studies*, 41(4), 513-41
70. PEG (Prayas Energy Group). 2003*, Good Beginning but Challenges Galore (Electricity Regulatory Commissions in India: Resource, Transparency and public Participation)* Survey undertaken in February 2003

71. Pereira, Carlos, Bernardo Mueller and Marcus Melo (2006) *Regulatory Governance in Infrastructure Industries; An Assessment and Measurement of Brazilian Regulators*, The World Bank, Washington DC.
72. Pereira, Carlos, Bernardo Mueller and Marcus Melo (2006) Regulatory Governance in Infrastructure Industries; An Assessment and Measurement of Brazilian Regulators, The World Bank, Washington DC.
73. Phillips Gr) C F. 1993 *The Regulation 0/ Public Utilities: theory and practice* Arlington: Public Utilities Reports, Inc.
74. Pillai, N, Vijayamohanan (1995), 'Liberalisation of Poverty', Paper presented in a Seminar on "Economic Issues Relating to Social Welfare in Post-Liberalisation India' on February 10, 1995 in the Dept. of Econometrics, Madras University, Chennai.
75. Pillai, N. Vijayamohanan (1999) ‘Reliability Analysis of Power Generation System: A Case Study’, *Productivity*, Vol. 40(2), July- September: 310 – 318.
76. Pillai, N. Vijayamohanan (2001) *Electricity Demand Analysis and Forecasting – The Tradition is Questioned!* Working Paper No. 312, February, Centre For Development Studies, Thiruvananthapuram.
77. Pillai, N. Vijayamohanan and Kannan, K. P. (2001) *Time and Cost Overruns of the Power Projects in Kerala*, Working Paper No. 320, October, Centre For Development Studies, Thiruvananthapuram.
78. Planning Commission, Government of India, New Delhi – draft report of the Expert Committee on Integrated Energy Policy 2005
79. Prayas Group (2003) A Good Beginning But Challenges Galore, Prayas Group, Pune, India.
80. Quinglian, He (2000) *China’s Descent into a Quagmire*, reprinted in *The Chinese Economy*, 33(3), May-June.
81. R. Howard, I. Nam, and J. Shin, “New Zealand, Korea Hold Rates,” *The Wall Street Journal Online Edition* (March 10, 2010), web site www.wsj.com (subscription site).

82. Rao S L. 2000*, Electricity reform and regulation* Economic and Political Weekly XXXV(26): 2231-34
83. Rao S L. 2001 *, Regulating Power The Telegraph*, 24 September 200I
84. Rao S L. 2001*, Perfect hindsight* PowerLine (May 2001)
85. Rao S L. 2001, *The last resort* PowerLine (December 2001)
86. Rao S L. 2003*, Competition in electricity Maharashtra Economic Development Council Journal* (July 2003)
87. Rao S L. 2003, *Competition Policy in Electricity and Other Fuels Bombay Management Association Review* (March-April 2003)
88. Rao, M. Govinda, Shand, R. T., and Kalirajan, K. P. (1998-99) 'State Electricity Boards: A Performance Evaluation', *The Indian Economic Journal*, Vol. 46(2), October-December.
89. Ripley-R. 1982*, Bureaucracy and Policy Implementation* Homewood: Dorsey Press
90. Rose-Ackerman, S. (1999) *Corruption and Government: Causes, Consequences and Reform*, Cambridge University Press, Cambridge.
91. Sathe S P. 1999 *, Administrative Law* (6th edn) New Delhi: Butterworths India
92. Sathe S P. 1999*, Administrative Law* (6th edn) New Delhi: Butterworths India
93. Schultze C L. 1977 *, The Public Use 0/ Private Interest* Washington, DC: Brookings Institution
94. Schwartz B and Wade. 1972*, Legal Control of Government: administrative law in Britain and the United States* Oxford: Clarendon Press
95. Schwartz B, et al. 1972 *Legal control of government: Administrative law in Britain and the United States* Oxford: Clarendon Press
96. Schwartz B. 1994 *, Administrative Law* London: Little, Brown, and Co.
97. Schwartz B. 1994*, Administrative Law,* p. 12 London: Little, Brown, & Co.
98. Sellers J M. 1984 *, Regulatory values and the exceptions process* Yale Law Journal 93: 943-45
99. Shapiro D L. 1965, *The choice of rule making or adjudication in the developments of agency policy* Harvard Law Review, pp. 947-52

100. Singh N K and Jha V. 200 I ,’ *Liberalization and the growth of regulatory agencies -* Indian Review
101. Sinha, Nikhil (1996) The political economy of India’s telecommunications reforms, Telecommunications Policy, 20, pp. 23-38.
102. Spiller P T. 1996*, A positive political theory of regulatory instruments: contracts, admnistrative law or regulatory specificity?* Southern California Law Review Ganuary 1996)
103. Stern, J, S Holder (1999) *Regulatory governance: criteria for assessing the performance of regulatory systems.* An application to infrastructure industries in the developing countries of Asia. *Utilities Policy*, 33-50.
104. Stewart R B. 1975 *The reformation of American administrative law* Harvard Law Review 88: 1671-75
105. Sundar Sand Sarkar S K. 1999 *, ‘Framework for regulation: the Indian experience’*
106. *‘In Transition to a Liberalized Environment: experiences and issues in regulation*, edited by L Srivastava and S K Sarkar, pp. 39-53 New Delhi: Tata Energy Research Institute
107. Sunstein C R. 1990 *, Law and administration after Chevron* Columbia Law Review 90: 2078-79
108. Tang B. 2000 *, Government: Regulatory Perspective* Available online at http://www.apec-finsecreg.org/MRCProgram/SessionII-TangPDF.
109. Turnbull P. 1999 *, Regulation or Re-regulation of Transport?* [Discussion Paper]
110. Geneva: International Labour Organization [Available online at www.oftel.gov.uk/publications/about_oftel/ whit0700.htm.
111. U.S. Department of Energy, Loan Guarantee Program, *“Key Documents: Title XVII. Incentives for Innovative Technologies”* (August 8, 2005), web site www.lgprogram.energy.gov.
112. United Nations, ‘*World Economic Situation and Prospects 2010’* (New York, NY, 2010), pp. 125-126,web site www.un.org/esa/policy/wess/wesp2010 files/wesp2010.pdf.

113. Vickers, J., G Yarrow (1988) *'Privatization: An Economic Analysis'*, MIT Press Ltd, London, UK.
114. 'Weatherly R, et al. 1977 *'Street-Level Bureaucrats and Institutional Innovation in Implementing Special Educational Reforms'* Harvard Educational Review 17(2): 171-97
115. Electricity Regulatory Commissions Act - 1998
116. Electricity Act – 2003
117. National Electricity Policy – 2005
118. National Tariff Policy – 2006
119. Consolidated Works Report of Indian Aluminium Company Limited for the periods 2002-03 & 2003-04
120. Cost report of Indian Aluminium Company Limited for the period 2002-03 and 2003-04

Websites:

http://powermin.gov.in	:	Website of Ministry of Power, Government of India, New Delhi
http://www.erckerala.org	:	Website of Kerala State Electricity Regulatory Commission, Trivandrum
http://www.cercind.gov.in	:	Website of Central Electricity Regulatory Commission , New Delhi
http://aptel.gov.in	:	Website of Apellate Tribunal of Electricity, New Delhi
http://www.dae.gov.in	:	Website of Department of Automic Energy, Government of India, Delhi
http://cea.nic.in	:	Website of Central Electricity Authority, Government of India, Delhi
http://www.beeindia.in	:	Website of Bureau of Energy Efficiciency, Ministry of Power, Government of India
http://www.kerc.org	:	Website of Karnataka Electricty Regulatory Commission

http://www.wberc.net : Website of West Bengal Electricty Regulatory Commission

http://www.uperc.org : Website of Uttar Pradesh Electricty Regulatory Commission

http://tnerc.tn.nic.in : Website of Tamil Nadu Electricty Regulatory Commission

http://www.aperc.gov.in : Website of Andhra Pradesh Electricty Regulatory commission

http://www.derc.gov.in : Website of Delhi Electricty Regulatory Commission

http://www.gercin.org : Website of Gujarat Electricty Regulatory Commission

http://www.pserc.nic.in : Website of Punjab State Electricty Regulatory Commission

http://www.orierc.org : Website of Orissa Electricty Regulatory Commission

http://www.mercindia.org.in : Website of Maharashtra Electricty Regulatory Commission

http://herc.gov.in : Website of Haryana Electricty Regulatory Commission

http://jercuts.gov.in : Website of Joint Electricity Regulatory Commission for the State of Goa and Union Territories

http://india.gov.in : Website of Government of India

http://kerala.gov.in : Website of Government of Kerala

http://www.kseb.in : Website of Kerala State Electricity Board

http://www.kseb.in : Website of KSEB Officers Association

http://epw.in : Website of Economic & Political Weekly

http://planningcommission.nic.in : Website of Planning Commission, Govt of India, Delhi

http://www.forumofregulators.gov.in :Website of Forum of Regulators

ANNEXURE – I

ABBREVIATIONS

ABT	Availability Based Tariff
AC	Alternating Current
ADB	Asian Development Bank
ALCAN	Aluminium Company of Canada
AP	Andhra Pradesh
APDRP	Accelerated Power development and Reform Programme
APERC	Andhra Pradesh Electricity Regulatory Commission
ARR & ERC	Aggregate (or Annual) Revenue Requirement and Expected Revenue from Charges
AT&C loss	Aggregate Technical and Commercial Loss
ATE	Appellate Tribunal of Electricity
BDPP	Brahmapuram Diesel Power plant
BPL	Below Poverty Line
BSES	Bombay Sub-urban Electric Supply Company L:imited
BST	Bulk Supply Tariff
Btu	British Thermal Unit
C&AG	Comptroller and Auditor General
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CFL	Compact Fluorescent Lamp
CGS	Central Generating Station
Ckt Km	Circuit kilometre
ckm	Circuit kilometre
CNG	Compressed Natural Gas
CPP	Captive Power Plant
DERC	Delhi Electricity Regulatory Commission
DGVCL	Dakshin Gujarat Vij Company Limited
DISCOM	Distribution Company
DPC	Dhabol Power Company
DPR	Detailed Project Report
DT	Distribution Transformer
EA-2003, E-Act	Electrical Act -2003
EHT	Extra High Tension
EIA	Energy Information Administration
ERC	Electricity Regulatory Commission
ERC Act-1998	Electricity Regulatory Commissions Act-1998
ESAAR	Electricity (Supply) Annual Account Rule
FACT	Fertilizers & Chemicals Travancore Limited
FBR	Fast Breeder Reactor
FO	Fibre Optic
FOCA	Fuel and Other Cost Adjustments
GDP	Gross Domestic Product
GE	General Electric
GSEC	Gujarat State Electricity Corporation Limited

GUVNL	Gujarat Urja Vikas Nigam Limited
GW	Gegawatt
HSD	High Speed Diesel
HT	High Tension
HVDC	High Voltage Direct Current
Hz	Hertz
IEO-2010	International Energy Outlook-2010
INDAL	Indian Aluminium Company Limited
IPP	Independent Power Producer
IRC	Independent Regulatory Commission
ITER	International Thermonuclear Experimental Reactor
kA	Kilo Ampere
KCal	Kilo Calories
KDDP	Kozhikkode Diesel Power Plant
KPCL	Kasaragode Power Company Limited
KSEB	Kerala State Electricity Board
KSERC	Kerala State Electricity Regulatory Commission
kVA	Kilo Volt Ampere
KWA	Kerala Water Authority
kWh	Kilo-Watt Hour (Unit)
LDC	Load Dispatch Centre
LED	Light Emitting Diode
LF	Load Factor
LNG	Liquefied Natural gas
LRMC	Long Range Marginal cost
LSHS	Low Sulphur Heavy Stock
LT	Low Tension
MAPS	Madras Atomic Power Plant
MD	Maximum Demand
MERC	Maharashtra Electricity Regulatory Commission
MGVCL	Madhya Gujarat Vij Company Limited
MoP	Ministry of Power
MSEB	Maharashtra State electricity Board
MU	Million Unit
MW	Megawatt
MYT	Multi-Year Tariff
NDA	National Democratic Alliance
NEP	National Electricity Policy
NHPC	National Hydro Power Corporation
NLC	Neyveli Lignite Corporation
NPCI	Nuclear Power Corporation of India
NSG	Nuclear Suppliers Group
NTP	National Tariff Policy
NTPC	National Thermal Power Corporation
OECD	Organisation for Economic Cooperation and Development
O&M	Operation & Maintenance
OPEC	Organisation of Petroleum Exporting Countries
PBR	Performance Based Regulation

PF	Power Factor /Provident Fund
PGCIL	Power Grid Corporation of India Limited
PGVCL	Paschim Gujarat Vij Company Limited
PHWR	Pressurised Heavy Water Reactor
PLCC	Power Line Carrier Communication Network
PLF	Plant Load Factor
PPA	Power Purchase Agreement
PSU	Public Sector Unit
PTC	Power Trading Corporation
RC	Regulatory Commission
RE	Renewable Energy
RGCCPP	Rajiv Gandhi Combined Cycle Power Plant
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
RLDC	Regional Load Dispatch Centre
RMD	Recorded maximum Demand
RoE	Return on Equity
RST	Retail Supply tariff
RSTPS (RSPTS)	Ramagundam Super Thermal Power Station
RTU	Remote Terminal Unit
SCADA	Computerised Supervisory Control and Data Acquisition System
SEB / EB	State Electricity Board / Electricity Board
SHP	Small Hydroelectric Project
SLDC	State Load Dispatch Centre
SRLDC	Southern Regional Load Despatch centre
T&D Loss	Transmission and Distribution Loss
TCC	Travancore Cochin Chemicals Limited
TN	Tamil Nadu
TNEB	Tamil Nadu electricity Board
ToD	Time of Day
TRAC	Tariff Regulatory Assistance Cell
TRAI	Telecom Regulatory Authority of India
TRANSCOM	Transmission Company
UG	Underground
UGVCL	Uttar Gujarat Vij Company Limited
UI	Unscheduled Interchange
ULDC	Unified Load Dispatch Centre
UP	Uttar Pradesh
UPA	United Progressive Alliance
WEG	Wind Energy Generators

ANNEXURE – II

LIST OF REGULATIONS ISSUED BY KSERC

1.	KSERC Tariff Regulations, 2003
2.	KSERC Fuel Surcharge Formula Regulations, 2009
3.	KSERC Conduct of Business Regulations, 2003
4.	KSERC (Conduct of Business) Amendment Regulations, 2010
5.	Kerala Electricity Supply Code, 2005
6.	Kerala Electricity Supply Code (First Amendment), 2005
7.	Kerala Electricity Supply Code (Second Amendment),2007
8.	Kerala Electricity Supply Code (Third Amendment),2008
9.	Kerala Electricity Supply Code (Fourth Amendment),2008
10.	Kerala Electricity Supply Code (Fifth amendment), 2009
11.	KSERC Appeals Before Appellate Authority Regulations, 2005
12.	KSERC Open Access Regulations, 2005
13.	KSERC Accounting Regulations, 2005
14.	KSERC CGRF & Electricity Ombudsman Regulations, 2005
15.	KSERC CGRF & Ombudsman (First Amendment) Regulations 2007
16.	KSERC CGRF& Ombudsman (Second Amendment) Regulations, 2008
17.	KSERC (CGRF & Ombudsman) 3rd Amendment Regulations, 2010
18.	KSERC (CGRF & Elec. Ombudsman) 4th Amendment Regulations, 2010
19.	KSERC (CGRF & Ombudsman) (Fifth Amendment) Regulations, 2011
20.	KSERC Conditions of License for STU, 2005
21.	Kerala State Electricity Grid Code, 2005
22.	KSERC Conditions of license for Existing Distribution licensees, 2006
23.	KSERC Conditions of License for Existing Distribution Licensees (1st Amendment), 2009
24.	KSERC Licensing Regulations, 2006
25.	KSERC Terms and Conditions for Retail sale Regulations, 2006
26.	KSERC Terms and Conditions of tariff under MYT for Distribution and retail sale Regulations, 2006
27.	KSERC Power Procurement from Renewable Sources Regulations, 2006
28.	KSERC Power procurement from Renewable sources (First Amendment) Regulations, 2008
29.	KSERC (Power Procurement from Renewable Sources by Distribution Licensee) 2nd Amendment Regulations, 2010
30.	KSERC Power procurement from Co-generation Sources Regulations, 2008
31.	KSERC Power procurement from captive sources Regulations, 2007
32.	KSERC Fees Regulations, 2007
33.	KSERC licensees standards of performance Regulations, 2006
34.	KSERC licensees Standards of Performance (First Amendment) Regulations, 2009
35.	KSERC Conditions of Service -Ombudsman Regulations, 2008
36.	KSERC (Renewable Purchase Obligation & Its Compliance) Regulation, 2010
37.	KSERC (Power Procurement from Solar Plants by Distribution Licensees) Regulation 2009

ANNEXURE-III

COPY OF GOVERNMENT ORDER SANCTIONING RELIEF TO INDAL

GOVERNMENT OF KERALA
Abstract

Power Department – M/s Indian Aluminium Company Limited (INDAL) – Relief – Sanctioned – Orders issued

---

POWER (A) DEPARTMENT
G.O.(Rt) No. 163/03/PD. Dated Thiruvananthapuram 24-4-2003

Read:- Representation dated 2.1.2003 from the Chief General Manager, Indian Aluminium Company Limited (INDAL)

ORDER

M/s Indian Aluminium Company (INDAL) in their representation read above has requested for certain concessions with a view to offset the loss on account of increase in power tariff. The company has informed that the cost of power now constitutes approximately 61 % of cost of production and they have no other option but to de-energise their smelting operations and hence they have given notice to Kerala state Electricity Board to reduce their contract demand to 5000 KVA and to terminate the 2500 KVA agreement for the pollution control equipment. They have also pointed out the importance of this industry in Kerala and the implication of closure of the company on the workforce, i.e. around 800 people directly employed and a large number of workers indirectly employed. M/s INDAL has requested for the following relief:-

1. To introduce incentives for high power factor and high load factor and also to introduce off peak incentives and bulk discounts.
2. To maintain power tariff based on incentives for a period of 3 years.
3. To allow direct purchase of power from outside the state for captive use.

Government have also received a number of representations requesting for immediate action for preventing the Indian Alumium Company, Eloor from closing down.

Government have considered the issue in detail and in view of the probable plight of employees and workforce if the management resorts to shutdown of the plant as has been indicated in the notice served by the company and in view of the notice issued to the Kerala State Electricity Board to reduce demand for power from 25 MVA to 5 MVA from January 2003 onwards, they are pleased to allow Rupees One Crore per month for a total period of three months to M/s INDAL by way of relief. The financial commitment on this account shall be shared by the Government and the Kerala State Electricity Board on 50/50 basis.

(By the order of the Governor)

LIZZIE JACOB
Principal Secretary to Government

To

The Chief General Manager, Indian Aluminium Company Limited, Alupuram, Kalamassery

The Chairman, Kerala state Electricity Board

The Secretary, KSEB

The Accountant General (A&E)/(Audit), Kerala

The Finance Department

The industries department

The General Administration (SC) Department (Vide item No. 1890 dated 21-04-2003)

FORWARDED /BY ORDER

(Signed)
SECTION OFFICER

Copy to : PS to Chief Minister

PS to Minister (Electricity)

PS to Minister (Industries)

PA to Principal Secretary (power)

ANNEXURE – IV
KSERC ORDER ALLOWING WHEELING OF 30 MW TO INDAL

KERALA STATE ELECTRICITY REGULATORY COMMISSION
THIRUVANANTHAPURAM 695 003

PRESENT: Shri M.K.G. Pillai, Chairman
Shri C. Balakrishnan, Member

January 14, 2004

Petition No. DP-6	Dy. No. 00113 dtd. 24-06-2003	Indian Aluminium Co. Ltd., Alupuram, Kalamassery 683 104. Kerala State Electricity Board,Thiruvananthapuram.	Petitioner Respondent

ORDER

1. Background:

1.1 The petitioner, Indian Aluminium Co. Ltd., Alupuram, hereinafter called Indal is an extra high-tension consumer availing power at the voltage of 110 kV from the Kerala State Electricity Board hereinafter called the KSEB or Board. The petitioner has stated that aluminium smelting, the activity in which it is engaged, is a power intensive industry and cost of power is the single most important driver in the cost of production. Cost of power at the existing tariff formed over 65% of the total cost of production while for the smelters abroad, the energy cost averages to only 20%. The selling price of aluminium is independent of the cost of individual producers, being governed by the London Metal Exchange (LME) price and market conditions. LME price has been reducing in real terms over the past several years.

The petitioner further stated that between 1997 and 1999, the KSEB hiked tariff five times, raising it from Rs 1.12 per kWh to Rs 2.4 per kWh. KSEB hiked EHT tariff with effect from August 1, 2001 by a further 25% and again hiked the tariff by another Ps. 50 per kWh with effect from 1st October, 2002. The tariff as applicable now is Rs. 3.35 per kWh. The petitioner has stated that being critically dependent on the power cost, where a hike of Ps. 10 per kWh would increase the metal cost by about Rs. 1700/- per tonne, the smelter has become completely unviable due to the frequent hike in tariff. From a profit-making unit of Indal, the smelter has now turned into a loss making unit. The hike in power tariff has resulted in an annual loss of Rs. 24 Crores.

Under the circumstances, the petitioner was compelled to look to other sources of supply of less costly power. The Power Trading Corporation has agreed to supply power to the petitioner at the rate of Rs. 2.50 per kWh at the point of interconnection between the Kerala Transmission System and Southern Region Transmission System. The power received at the interconnecting point is to be transmitted to the smelter located at Alupuram, Kalamassery using the transmission system of KSEB. The petitioner has therefore requested the Commission to allow it to avail power from PTC using the transmission system of the KSEB on open access basis in accordance with the provisions of the Electricity Act, 2003 and also decide on the wheeling charges, *etc.,* for the usage. The petitioner suggested a wheeling charge including losses, not exceeding Ps. 10/kWh.

1.2 The petition was notified to the KSEB on 3.7.2003 requesting for its response to the petition. The Government of Kerala were also requested to offer the views of the Government in the matter.

The KSEB in its reply dated 4.8.2003 stated that the present network of KSEB would become insufficient to transmit KSEB's entitlement from the Central Sector Power Stations located outside Kerala, which may reach a level of 900-1000 MW in the immediate future. The Board also pointed out certain constraints in the 400/220 kV transformer capacity for availing power by Indal through the Madakkathara 400/220 kV substation. The Board suggested fixing the transmission charges at Ps. 35/kWh based on the transmission charges for the transmission system associated with the Kayamkulam power station of NTPC. The Board also demanded transmission losses @ 8% of the transmitted energy, a surcharge of Ps. 42/kWh and an additional surcharge to offset the commitment charges.

1.3 The response of the Board was notified to Indal seeking their views on the demands of the KSEB. The petitioner in its rejoinder filed on 15^{th} August 2003 refuted the contention of the KSEB regarding transmission constraints. The petitioner stated that the Board had a normal transmission capacity of 1100 MW for import of power from outside the State, if the capacities of all the inter-State 400 kV and 200 kV lines were utilized. The maximum import so far made by KSEB was 620 MW in April 2003 when the hydel generation was an all time low. The petitioner contented that the quantum of import of power by KSEB, under any circumstance would not exceed 750 MW in the near future. To reinforce the argument, the petitioner quoting from the budget of the KSEB, stated that the power purchase projection for 2003-04 was only 6156 MU including that from power stations of other agencies located within the State. Further, by Board's own admission, the 400 kV Madurai-Thiruvananthapuram line and associated substation would be commissioned by December, 2003. The petitioner therefore contented that the Board's transmission system had sufficient capacity for transmission of 30 MW of power, as sought by the petitioner. The petitioner further stated that the maximum import by KSEB through the 400/220 kV substation at Madakkathara had never exceeded 400 MW and therefore there would not be any difficulty of importing additional 30 MW for the use by the petitioner, as the transformers at Madakkathara substation had a capacity of 630 MW.

As regards transmission charges, the petitioner contented that the charges should be worked out on the basis of the depreciation of the original cost of the transmission system from Madakkathara to Kalamassery, interest on loan, if any, and O&M expenses and pro-rata charges for 30 MW apportioned against the maximum loading of 400 MW for the transmission lines. The petitioner has estimated that the transmission charges for transmission of power from Madakkathara to Indal Alupuram Smelter premises would be Ps 2.5/kWh only. The petitioner has pointed out that the wheeling charge levied by the Board on TNEB for transmitting power through Moozhiyar-Theni 220 kV feeder was only Ps 2.5/kWh. The petitioner has therefore contented that the transmission charges for transmitting power from Madakkathara to Indal should not exceed Ps 2.5/kWh.

As regards transmission losses, the petitioner has contented that the transmission loss of 8% claimed by the Board included losses in the 220 kV, 110 kV and 66 kV systems. The actual transmission loss in 220 kV system would be much lower than 2%. As per the calculation submitted by the petitioner, transmission loss for transmitting power from Madakkathara to Indal would work out only to 2.54%.

As regards surcharge to compensate the cross subsidy, the petitioner stated that the cross subsidy should be determined by comparing the Board's average cost of supply with the tariff rate for the consumer. Therefore the question of cross subsidy would arise only when the tariff of a particular consumer is more than the average cost of supply. Since in this particular case, the average cost of supply is Rs 3.99/kWh and the average tariff rate of the consumer (petitioner) is Rs 3.38, there was no cross subsidy applicable to the petitioner. The petitioner was therefore not liable to pay any surcharge to the Board.

1.4 In response to certain clarification sought by the Commission from the KSEB on 6th August, 2003, the KSEB furnished the reply on 25th August, 2003.

On the query regarding quantum and direction of power flow on the 220 kV system, the KSEB has informed that power flow is from Idukki/Bhramapuram to Kalamassery and from Lower Periyar/Idukki to Madakkathara under all operating conditions. The Board did not furnish details of calculation for arriving at the transmission loss of 8%.

Board further stated that fixed charges on account of withdrawal of 30 MW by Indal would cause an additional liability of approximately Rs 2 crores per month which need to be compensated by Indal.

1.5 Indal surrendered the power supply by KSEB to the smelter plant with effect from 1.8.2003.

2. **Hearing of the Matter**

2.1 In the proceedings of the Commission held on 2.9.2003, the parties to the petition were heard.

2.2 The representatives of the petitioner reiterated the arguments made in the petition and the subsequent rejoinder to the response of the KSEB. The petitioner contented that there was no transmission constraint in transmitting 30 MW power from the interconnecting point at Madakkathara to the Aluminium smelter plant at Alupuram. The representatives of the petitioner stated that till recently the smelter plant was receiving about 30 MW from the KSEB system. This quantum of power physically flowed from the BSES power station to the smelter plant and the same situation will continue even after delivery of 30 MW at Madakkathara by PTC. The only difference would be that generation in the KSEB system in the southern part could be correspondingly reduced. The total capability of import of power into KSEB system was around 1100 MW and the actual import requirement in the immediate future would not exceed 750 MW. The petitioner also contented that there was adequate margin in the 400/220 kV transformer capacity at Madakkathara to permit import of 30 MW of power required by the petitioner. The petitioner therefore pleaded for allowing open access to the transmission system of KSEB for importing 30 MW of power from PTC at Madakkathara and transmitting the power to the smelter plant at Alupuram.

On transmission charges, the petitioner stated that the demand of KSEB for a transmission charge of Ps 35/kWh was exorbitant. The petitioner argued that it was unscientific to base the transmission charges on the cost of transmission for Kayamkulam power station as the transmission system associated with the station was dedicated for transmitting the power from the station alone. The cost of transmission would vary depending on the quantum of energy generated at the station and the capital cost. If the generation was low, the per unit transmission charges would be high. The charges would be still higher in the case of Kayamkulam transmission system since it was constructed very recently with huge capital investment. The petitioner pointed out that for supply of Kayamkulam power to Tamil Nadu, KSEB was charging only Ps 2.5/kWh for usage of the 220 kV Moozhiar-Theni line of KSEB. The representatives of the petitioner also quoted an instance where the Central Electricity Regulatory Commission had fixed the tariff @ Ps 2.5/kWh for usage of 220 kV transmission system of Grid Corporation of Orissa by the Madhya Pradesh Electricity Board. The petitioner also stated that in the concept paper on open access in Inter-State Transmission brought out by the Central Electricity Regulatory Commission, the transmission charge has been worked out as Ps 1.98/kWh for 100 KM usage of transmission system. The petitioner stated that taking into account the transmission systems between Madakkathara and Alupuram, the transmission charges would not exceed Ps 2.5/kWh. The petitioner therefore pleaded that the transmission charge should not be fixed higher than Ps 2.5/kWh.

As regards transmission losses, the petitioner stated that the power flow would be by displacement. While the petitioner would be physically drawing power from the BSES power station, the 30 MW power received at Madakkathara would be flowing to North Kerala. The representatives of the petitioner argued that the KSEB would be in a position to reduce power generation to the extent of 30 MW in the power stations in the southern part of the State with consequent reduction in the power flow from southern part to Madakkathara. On account of this, there would be reduction in losses. However, even if the losses were calculated on the basis of contracted path method from Madakkathara to Alupuram, the actual loss would work out only to 2.54%. The petitioner therefore pleaded that the transmission losses should not be fixed higher than 2.54%.

As regards the demand for surcharge towards cross subsidy, the petitioner stated that the question would arise only when the tariff of a particular category of consumer was more than the average cost of supply. Since the KSEB's average cost of supply and the petitioner's tariff were stated to be Rs 3.99/kWh and Rs 3.38/kWh respectively, the petitioner was not liable to pay any surcharge towards cross subsidy. The petitioner further stated that presently KSEB was meeting its demand partly through power purchase. The cost of power purchase in certain cases was as high as Rs 4.50 /kWh. Hence if 30 MW power was wheeled to the petitioner from outside the State, the KSEB could reduce the power purchase to the same extent from costly sources. Thus, the KSEB would stand to gain to the extent of Rs 1.12 per kWh (Rs 4.50 - Rs 3.38) during the operation of wheeling of power to the petitioner. The petitioner, therefore, stated that even if it was admitted for the sake of argument that there was a loss of Ps 42/kWh on account of cross subsidy factor, the loss would be well compensated by the gain of Rs 1.12 per kWh through reduction of purchase of costliest power. The petitioner therefore pleaded for exemption from payment of surcharge towards cross subsidy. The petitioner also argued against the additional surcharge as the entire demand of the petitioner would be met by PTC continuously and no additional facility was needed to be created for the proposed wheeling of 30 MW of power.

2.3 The representatives of the workers' Union of Indal stated that the production in the plant was getting affected due to the frequent revision in the power tariff by the KSEB and Indal was scaling down production through gradual layoffs. The operation of the smelter plant has been totally stopped with effect from 1.8.2003. Indal is presently maintaining only marginal operations with power intake of 5 MW. The workers apprehended that even this small scale operation may come to a stop in course of time. As a result of this, about 1000 workers would become jobless which might adversely affect about 5000 affiliated families. This may affect the industrial climate of the State besides loss of direct and indirect revenue to the Government to the extent of Rs 80 crores per annum. Closure of Indal may also come in the way of flow of investment for new industrial ventures in the State. The representatives of the Workers' unions pleaded for every possible action on the part of the Commission, Government of Kerala and the KSEB in restarting the smelter plant, as early as possible.

2.4 The representative of the Government of Kerala stated that the State Government had no objection in permitting open access to the transmission system of KSEB for delivering power to Indal by PTC subject to technical suitability of the proposal. The Government representative stated that the Commission might decide the wheeling and other charges applicable to the case.

2.5 The representatives of the KSE Board stated that considering the power entitlement of KSEB in the Central Sector Stations and also the contracted power from other sources outside the State, the total power import in the immediate future would be of the order of 1170 MW. The existing transmission capacity would not be adequate to facilitate import of this quantum of power. The 400/220 kV transformer capacity at Madakkathara also imposed a constraint on import of additional power. However, since the requirement of Indal was only of the order of 30 MW, the Board would not raise any objection for permitting this import by Indal.

As regards charges for transmitting power to Indal using the transmission system of KSEB, the representatives of KSEB stated that as the actual power flow would take place through displacement in an interconnecting network, the transmission charges were necessarily to be worked out on the basis of the pooled cost of transmission in the State. However, as the valuation of assets and other costs relating to the transmission profit centre of the Board had not been worked out separately, it was not possible to arrive at the appropriate value for the transmission/wheeling charges, on this basis. Pending calculation of the transmission tariff on pooled cost basis, the Board would opt for deciding the transmission tariff on the basis of transmission charges paid by the Board to POWERGRID for Kayamkulam transmission system, as this transmission system formed an integral part of the overall transmission system in the State. Presently the charges for Kayamkulam transmission system worked out to Ps 35/kWh. The Board therefore pleaded that the transmission charges for usage of KSEB's transmission system by Indal should be fixed at Ps 35/kWh.

As regards losses in the transmission system, the Board's representatives stated that presently the average transmission losses at EHT level worked out to 7.1% and allowing for incremental losses for transmission of additional power of 30 MW, the losses would work out to 8% and therefore the power transfer to Indal should provide for transmission loss of 8%. On a query from the Commission, the Board's representatives stated that this included also the losses in the 66 kV system.

The Board's representatives further stated that the Board was entitled for a surcharge based on the difference between tariff for Indal and average realization by the Board. The average charges for Indal worked out to Rs 3.36/kWh including electricity duty of Ps 1/kWh and surcharge of Ps 2.5/kWh. As the average realization was Rs 2.96/kWh, it was argued that the Board was entitled for a surcharge of Ps 40/kWh. It was also argued that the Indal should also pay an additional surcharge of Rs 2 crores per month towards the liability of the Board by way of fixed charges to be paid to independent power producers. The representatives of the Board further stated that in the event of failure of power supply from PTC, if Indal desired to avail supply from KSEB, it should be liable to pay Rs 2 crores per month as grid support charges in addition to the normal supply tariff of the KSEB.

2.6 The representatives of Indal disputed the arguments of KSEB in regard to transmission charges, losses and surcharge. They reiterated that the Kayamkulam transmission system was dedicated to the Kayamkulam power station and was constructed with 400 kV parameters and the transmission system therefore had a much higher capacity than the 220 kV system. Working out the transmission charge on the basis of Kayamkulam transmission was unscientific as the transmission charge was dependent on the power generated at Kayamkulam. Therefore the petitioner argued that a transmission charge of Ps 35/kWh based on the Kayamkulam transmission charges was unjustified.

As regards transmission losses, the representatives of the petitioner reemphasised that power imported at Madakkathara would generally flow to the northern parts of the State and the requirements of power in the central areas would be met from the local generation and actually there would not be any physical transmission of imported power from Madakkathara to Indal over the dedicated path, as a result of which there would be a reduction in losses to the extent of 0.2 MW in the KSEB's 220 kV system. Thus there would be an indirect gain for the KSEB due to the import of 30 MW for Indal. The petitioner argued that this point also should be taken into account while fixing the wheeling losses for the petitioner.

The representatives of the petitioner further stated that the load of Indal was such that the energy drawls remained more or less constant with a load factor of around 96%. However in the event of minor variations in actual practice, overdrawals / underdrawals might take place to some extent. Therefore, the petitioner suggested that actual energy schedule for drawal should be made on monthly basis.

2.7 Subsequent to the hearing on 2.9.2003, the KSEB vide letter No.TRAC/SERC/INDAL/440 dated 16.10.2003 raised its claim towards total wheeling charges for transmission of power to Indal to Ps.147 per unit of energy as per the following brake-up:

		Ps.
1	Wheeling Charges	32/40
2	Additional surcharge for compensating fixed cost of transmission and distribution	03
3	Surcharge to compensate revenue loss	96/88
4	Load despatch, scheduling and system operation charges	10
5	ROE	<u>06</u>
		147

The claim was based on the assumption that power flow to Indal would be taking place over the Edemon-Sabarigiri-Pallom-Brahmapuram-Kalamassery-Indal feeders. The Commission vide letter No.12/4/KERC/2003/310 dated 21st October 2003 asked for details of load flow studies to substantiate the premise that power to Indal would be fed through the Edemon-Sabarigiri-Pallom-Brahmapuram-Kalamassery-Indal feeders and also the details of arriving at the cost per km of 220 kV and 110kV lines considered by the KSEB in working out the transmission charges. KSEB was also asked to furnish the details of other assumptions made in the letter including the cost of supply to Indal when the KSEB was supplying power. The KSEB has not yet furnished these details.

3. **Commission's Findings:**

3.1 Indal has closed down the smelter plant with effect from 1.8.2003 and reduced its power intake from 30 MW to 5 MW. This development is a matter of serious concern to the Commission as the KSE Board has lost a major industrial consumer and it will further aggravate the already strained finances of the KSEB. The reduction in revenue collection by the KSEB on account of the closure of smelter plant is estimated to be around Rs. 5.5 Crores per month on an average. The average realization from Indal was Rs. 3.38 per kWh excluding electricity duty of Ps. 1/kWh and surcharge of Ps. 2.5 per kWh. The present level average realization by KSEB per kWh of energy sold is Rs. 2.96. Therefore the loss to KSEB due to the closure of Indal or grant of permission to Indal for availing power from PTC as requested in the petition of Indal would be Ps 42 per kWh of the energy consumption of the smelter plant. The KSEB has not indicated any strategy to deal with the situation arising out of the closure of Indal, even though the Commission had made a specific reference to the Board in this regard.

3.2 During the hearing, the representative of the Government of Kerala conveyed no objection to the proposal for open access subject to technical suitability and determination of transmission charges, etc., by the Commission. The KSE Board, in written response earlier had expressed reservations regarding permission of open access to Indal, citing transmission constraint as the reason. However, during the hearing, the representatives of the KSEB expressed the view that since the additional import was only to the extent of 30 MW, the Board would not object to granting permission to Indal for importing this quantum of power from PTC.

3.3 Under Subsection (2) (d) (ii) of section 39 and Subsection (2) of Section 42 of the Electricity Act, 2003, the Commission is vested with the authority to introduce open access for using the transmission system by a licensee or consumer and the Act allows sufficient time to the Commission for introduction of open access after framing regulations thereof. In the present case, Indal has surrendered the power and the smelter unit has become inoperative. It would appear that the smelter unit may get ultimately closed, if open access is not allowed. The Commission views this as an unprecedented and extraordinary situation warranting immediate decision, in the matter, by the Commission. During the hearing, the Government of Kerala and the KSEB have given in principle clearance for import of power by Indal from PTC using the transmission system of KSEB. Under the circumstances, the commission is inclined to allow open access to the transmission system of KSEB for use by Indal for transmitting the power purchased from PTC on an experimental basis. The Commission is therefore required to determine the charges to be paid by Indal to KSEB for such usage of the transmission system.

3.4 The components of the charges for permitting import of power by Indal from PTC would essentially cover the charges for usage of the transmission system of KSEB and compensation for transmission losses. As per sub-section 2(d) of Section 39 of the Act, any consumer provided with open access to the transmission system by a licensee is required to pay the transmission charges and a surcharge thereon, as may be specified by the State Commission and the surcharge shall be utilized for meeting the current level of cross subsidy. The Commission has to keep the above provision in the Act also in mind, while deciding the charges for permitting import of power by Indal.

3.5 As regards charges for usage of the transmission system, the petitioner has argued in favour of a transmission charge of Ps 2.5/kWh. In support of this, the petitioner has cited certain instances where similar charges were levied. The matter was examined in detail by the Commission. The Commission has found that the details of arriving at a transmission charge of Rs. 2.5/kWh, *viz*; the various components of the cost of transmission system, energy handled, distance of transmission, etc., have not been furnished. Further, it appears that the calculation is based on historical cost of the transmission system. The Commission is not in favour of deciding transmission charges on the basis of historical cost alone, as this approach will hamper development of the transmission system. In Commission's view, a combination of historical cost and opportunity cost need to be followed in deciding the transmission charges. As regards the transmission charge of Ps 1.98/kWh for 100 KM usage of 400 kV transmission system worked out by Central Electricity Regulatory Commission, it has been found that this is arrived at on the basis of a uniform loading of 500 MW on all the 400 kV lines. As actual loading on most of the lines would be much lower than this figure, the transmission charge may undergo an upward revision. Further, the proposal of CERC is in the form of a concept paper in draft stage, which may undergo many changes before finalization. The CERC has issued an interim order based on the existing tariff norms which is on pooled cost basis.

In view of the above, the Commission is not in a position to accept the proposal of the petitioner for fixing a transmission tariff of Ps 2.5/ kWh.

The Board, on the other hand, has stated that the transmission charge should be fixed on the basis of the charges for Kayamkulam transmission of POWERGRID which averages out to Ps 35/kWh. On scrutiny, the Commission has found that this figure has been arrived at by dividing the monthly transmission service charges by 100 million units. However, the average monthly generation at Kayamkulam power station is about 200 million units. This clearly shows that while working out the transmission charges, the Board has not taken into account the supply of 50% of the energy generation at Kayamkulam Station to Tamil Nadu. If this supply is also taken into account, the transmission charges on the basis of generation at Kayamkulam could workout Ps 17.5/kWh. The Commission notes that out of the two 220 kV double circuit transmission lines from Kayamkulam station, one line has been constructed with 400 kV parameters. On this basis, the total transmission capacity of the Kayamkulam transmission system would work out to about 800 MW. Thus, the monthly energy handling capacity of the transmission system, on a moderate scale, would be 400 million units per month. The transmission charges on this basis would work out to Ps 8.75/kWh. The Commission is also not in a position to consider the subsequent claim of KSEB for a total wheeling charge of Ps.147, since the supporting information called for by the Commission has not yet been furnished by the Board.

The Commission is therefore not agreeable to fix the transmission charges on the basis of the calculations furnished by the KSEB for working out charges for usage of the transmission system.

The Commission recognizes that there are different methods for working out the transmission charges, viz., pooled cost (postage stamp) method, contracted path method, MW-KM method, etc. In the particular case of import of 30 MW of power by Indal, as per the existing system configuration and operating conditions, most of the power would be received at Madakkathara 400 kV sub station. However, a part of the power, though small in quantum, may find its path over the other interconnecting lines. The situation may further change after the commissioning of the 400 kV Madurai-Thiruvananthapurm line, when a small portion of the power may find its path over this line also. This would mean that it would be difficult to distinctly identify the transmission path for transfer of 30 MW of power by Indal through the KSEB system. The Commission is therefore of the view that the most preferable method of determining the transmission charge is on the basis of the pooled cost of 220 kV transmission system in Kerala including the Kayamkulam transmission system. To this, the charges for usage of 110 kV transmission system from Kalamassery to Indal could be added. However, the KSEB was not in a position to furnish the cost details needed for arriving at the transmission charges on this basis.

Under the circumstances, the only option before the Commission is to arrive at the charges on the basis of the cost of a fairly new dedicated transmission system from Madakkathara to Alupuram, if constructed for transmission of 30 MW of power. The Commission collected cost data in this connection from various sources including the Central Electricity Authority. It has been found that the annual cost of such a transmission system apportioned for transfer of 30 MW power to Alupuram (over a distance of 70 KM) would work out to Rs. 2.2 crores. Based on an annual energy transfer of 240 million units, the cost per unit would work out to Ps 9/kWh. This may have to be increased by another Ps 1 /kWh as compensation for accommodating minor variations in power absorption on an instant to instant basis, SLDC charges, RLDC charges (if any) energy accounting charges, etc. Even though this rate of Ps 10/kWh may be higher than the normal charges for energy transfer over a 220 kV system of appropriate distance, the Commission feels that it would be necessary to adopt this figure in order to promote transmission system development in future. The Commission is therefore of the opinion that a charge of Ps 10/kWh should be fixed on composite basis to take care of transmission and related charges.

3.5.1 As regards system losses, the petitioner has worked out energy losses @ 2.54% on the basis of an absolute power flow of 30 MW over contracted path. The Board has estimated the energy losses @ 8% on pooled basis in the EHT system at 66 kV and above.

Based on the information furnished by the KSEB , the Commission has found that presently the power is flowing from Lower Periyar/Idukki to Madakkathara and from Madakkathara to northern Kerala under all operating conditions. This situation is likely to continue even after commissioning of the 400 kV Madurai-Thiruvananthapuram line. Import of 30 MW of power for Indal would therefore reduce the flow over the 220 kV Lower Periyar-Madakkathara and Idukki-Madakkathara lines. Thus there would be a reduction in the losses of the KSEB system due to the import of 30 MW power by Indal. However, the system conditions would not remain constant and might vary in accordance with the changes in system configuration and generation capacity additions. The Commission is therefore of the view that it would be necessary to keep an allowance to take care of the changing system conditions. As the loss worked out on contracted path basis is the lowest, it would be appropriate to adopt such a loss figure for this purpose. The Commission is however inclined to round off this figure to 3% since the calculation to arrive at a loss figure of 2.54% was made on the basis of absolute power flow and not on the basis of incremental power flow. The Commission is therefore of the view that the Board should be compensated for transmission losses to the extent of 3% of the energy transmitted.

3.5.2 As regards the surcharge on transmission charges, the petitioner has argued that since the average cost of supply by the Board is Rs. 3.99/kWh which is higher than the average tariff for Indal, the petitioner was not cross subsidizing any other type of consumer, and therefore no surcharge should be levied. The Board, on the other hand, maintained that average energy charges for Indal worked out to Rs 3.36 kWh while the average realization by KSEB was Rs 2.96/kWh and there was cross subsidization to the extent of Ps 40/kWh. Therefore the surcharge should be levied @ Ps 40/kWh. The Board has subsequently revised this figure to Ps.88/96.

The Commission is not in a position to accept both the above arguments. By definition, cross subsidy is the difference between the tariff for the consumer and the actual cost of supply to the consumer, if the former is higher than the latter. Although the Commission has sought the information regarding the cost of supply to EHT consumers at 110 kV, the KSEB was not in a position to furnish the same due to lack of data and asked for one year time to work out the details. Under the circumstances, the Commission is not in a position to decide the rate of surcharge based on the current level cross subsidy.

The Commission recognizes the fact that in deciding the various charges related to the import of 30 MW power by Indal, it has to strike a balance between two conflicting interests. Any adverse effect on the finances of the KSEB due to the transaction is detrimental to power development in the State. The continued closure of the smelter plant and the subsequent total closure of Indal would adversely affect the climate for industrial development with consequent setback to power development in the State. This is especially so, since the industrial consumption in the State is gradually coming down. The Commission firmly believes that it is impossible to sustain power development without industrial development.

In determining the rate for surcharge, the Commission has to ensure that there is no immediate financial loss to KSEB. In order to avoid financial loss to KSEB, it has to be compensated for the difference between the average tariff for Indal i.e. Rs. 3.38/kWh and the overall average realization of Rs 2.96/kWh for the energy supplied by KSEB. After taking into account the transmission charges and compensation for transmission losses as worked out above, it is felt that a levy of Ps 25/kWh towards surcharge would satisfy the above requirement.

3.8 The Commission considered the request of the KSEB for an additional surcharge of Rs 2 crores/month. As per the provisions of the Electricity Act, 2003, this surcharge is meant to meet the fixed cost of the licensee arising out of its obligation to supply. Since Indal has been an industrial consumer even before the constitution of the KSEB, the Commission finds no justification in calling upon the Company to pay any surcharge arising out of the Board's obligation to supply. Payment against commitment charges to Independent Power Producers has also no relevance under the power shortage conditions. The Commission is therefore not in a position to accept the request of the KSEB for the levy of additional surcharge on Indal.

4. Commission's decision:

4.1 In view of the foregoing discussion, the Commission in accordance with the provisions of Subsection 2(d)(ii) of Section 39 and Subsection(2) of Section 42 of the

Electricity Act, 2003 seeks to allow open access to Indal for import of 30MW of power using the transmission system of KSEB on an experimental basis.

4.2 *Transmission charges:*

Indal shall pay a composite transmission charge @ Ps 10/kWh to the KSEB for the energy delivered at Indal, Alupuram, which includes charges for accommodating minor instant to instant variations in power drawal, SLDC charges, RLDC charges (if any), accounting charges, etc.

4.3 *Transmission Losses:*

Indal shall compensate the KSEB for transmission losses at 3% of the energy injected into the KSEB system for transmission to Indal, Alupuram. This would mean that for every 100 units of energy injected into the KSEB system, KSEB would be liable to deliver 97units at Indal, Alupuram.

4.4 *Surcharge on transmission charges:*

Indal shall pay to KSEB a surcharge on the transmission charges @ Ps 25/kWh of energy delivered at Indal, Alupuram which will be reduced and eliminated in a phased manner as below:

From 1st April 2005	-	Ps 20/kWh
From 1st April 2006	-	Ps 15/kWh
From 1st April 2007	-	Ps 10/kWh
From 1st April 2008	-	Ps 5/kWh
From 1st April 2009	-	Nil

4.5 *KSEB shall accommodate minor variations in power absorption which may take place at any instant on the schedules prepared by the State Load Despatch Station and prepare the energy accounts on a monthly basis, which will be settled directly between Indal & PTC.*

4.6 *Indal and KSEB may mutually arrive at a suitable agreement regarding the terms and conditions for meeting the contingent conditions arising out of failure of power supply to Indal from PTC. Either of the parties may approach the Commission through suitable petitions for resolving any unsettled issue in this connection.*

4.7 *The above decisions of the Commission will not prohibit the parties to the petition including the successor bodies to the KSEB at a later date in filing review petitions with full supporting details thereof. The Commission's decision on such review petitions will only be operative prospectively.*

Petition No. DP-6 from Indian Aluminium Co. Ltd., Alupuram is disposed of accordingly.

Sd/-	Sd/-
C. BALAKRISHNAN MEMBER	M.K.G. PILLAI CHAIRMAN

Authenticated copy for issue

SECRETARY -IN-CHARGE

ANNEXURE – V

CONSOLIDATED LIST OF DIRECTIVES FROM THE HON'BLE COMMISSION TO THE BOARD

No.	Directives
	Order on ARR and ERC for FY03-04, Chapter VII, page 46-51
1	Receivables and collection efficiency – bring to the level of 98-99%, creation of Task Force to go in details for each case outstanding
2	Computerization of Billing and Meter Replacement
3	Schedules for optimizing internal generation and power purchase
4	Borrowings and Debt Servicing by KSEB - prepare and submit a white paper on the subject to the Government of Kerala, the Planning Board and the Commission latest by 31st January, 2004
5	Capital Works - submit a detailed investment plan for the capital works. Suggestion to submit investment plan well in advance of ARR&ERC filing
6	APDRP Schemes - revive the scheme and implement it more actively
7	Inventory Control - computerisation of the inventory and disposal of unwanted stores in the shortest possible time.
8	CoS - furnish the details regarding the cost of supply to the various categories of consumers and their consumption
	Order on ARR and ERC for FY04-05, Chapter VIII, page 59-62
1	Receivables and collection efficiency
2	Computerization of Billing and Meter Replacement
3	Schedules for optimizing internal generation and power purchase
4	Borrowings and Debt Servicing - revised white paper should be submitted to the Commission latest by 31.5.2004
5	Capital Works - submit a detailed investment plan for the capital works to be submitted in advance to ARR filing
6	Inventory Control - furnish a report on the subject latest by 15.5.2004.
7	R&M works - prepare a detailed work programme for R&M works during the year 2004-05
	Order on ARR and ERC for FY05-06, Chapter X, page 101-103
1	Compliance with the EA03: Cost of service study
2	Directives to comply with NEP: – File separate ARR and ERC in respect of transmission licence and distribution licence; separation of Load Despatch function; – Augmentation of SLDC; – File the proposal on principles of determination of wheeling charges before April 30, 2005
3	Directives in ARR and ERC: – Furnish Circlewise Demand-Collection-Balance (DCB) statements on monthly basis; – Maintain database of circle-wise, tariff category-wise, number of consumers, connected load, sales on monthly basis; – Detailed action plan to improve sales to industrial consumers;

	– File the segregation of voltage level technical losses and loss reduction plan; – Furnish operational details of diesel plants, availability of machines of the hydel plants; – Plan on borrowings and repayment; – Detailed function-wise physical and financial R&M programme for FY 2005-06; – Age-wise analysis of arrears and feasible plan to recover the arrears.
4	Capex - prepare comprehensive need based five year investment plan bringing out well defined objectives
	Order on ARR and ERC for FY06-07, Chapter X, page 113-120
1	Field Data on Demand/Load Growth and Sales Forecast
2	AT&C Loss reduction
3	Performance Evaluation and O&M Practices of Generating Plants
4	Employee Cost - report on man power rationalization
5	Interest and Debt Servicing – furnish proposed plan
6	Revenue Estimation – submit details on revenue estimation
7	Submit truing up petition for FY03-04, FY04-05
8	Submission of technical details requested by the Commission
	Order on ARR and ERC for FY07-08, Chapter XI, page 115-119
1	Submit a detailed Multi Year Tariff petition from FY 2008-09 with complete supporting data and analysis
	Monitoring and implementation of capital works – need based five-year investment plan
2	Introduction of new bill payment system; Faulty Meter Replacement - submit monthly reports on circle wise status of faulty meters and replacement of meters
3	Directives to comply with NEP - File separate ARR and ERC in respect of transmission license and distribution license; separation of Load Dispatch function; Augmentation of SLDC; file the proposal on principles of determination of wheeling charges
4	Segregation of voltage loss and loss reduction - submit the segregations of voltage level technical loss and loss reduction programme comprehensively.
5	Interest and Debt Servicing - furnish the proposed plan for further swapping of the loans and debt restructuring
6	Capex - approval of the Commission for all new projects; comprehensive need based five-year investment plan bringing out well-defined objectives
7	Submit the complete details with the breakup of arrears under each category of consumers with age wise analysis
8	R&M - submit the function wise physical and financial programme for R&M works
9	Demand and Energy Projections - furnish consumer category wise growth in numbers, connected load, energy consumption and demand projections
10	Employee Cost - study prepare a road map for reducing the employee cost in a sustainable manner.
11	Trouble call management - initial step the service to be extended to all urban centres in the present financial years and rural areas subsequently
12	Carbon Credits - The Board may explore the opportunity to earn carbon Credits
	Order on ARR and ERC for FY08-09, Chapter 8, page 74
1	Separation of Transmission and distribution loss
2	Separation of technical and commercial loss

3	The Board shall prepare a plan for meter replacement and the compliance should be closely monitored
4	The Board shall file a proposal on rationalization of ToD tariffs for the HT-EHT consumers
5	File a proposal for incentives linked energy efficiency programme aiming at reducing the peak load in the system
6	The Board shall prepare an implementation plan including procurement plan for all the important capital projects under generation, transmission and distribution
7	A detailed plan for realisation of the huge amount of arrear electricity charges shall be prepared and submitted to the Commission.
8	A proposal for introducing ToD tariff for LT industrial consumers above 50Kva may be submitted considering the revenue implication and reducing the peak demand
	Order on ARR and ERC for FY09-10, Chapter 8, page 83-84
1	Separation of transmission and distribution loss
2	Separation of technical and commercial loss
3	The Board shall prepare a plan for meter replacement and the compliance should be closely monitored with report to the Commission.
4	The Board shall file a proposal on rationalization of ToD tariffs for the HT-EHT consumers.
5	The Board shall file a proposal for incentives linked energy efficiency programme aiming at reducing the peak load in the system within two months from this order. Board shall initiate a study for assessing loss levels in 33kV/11kV system and LT system separately.
6	A proposal for incentivizing the off peak consumption shall be filed by the Board within two months.
7	The Board shall prepare an implementation plan including procurement plan for all the important capital projects under generation, transmission and distribution with information to the Commission; The Board shall file scheme wise details of investment proposed for approval
8	A detailed plan for realisation of the huge amount of arrears of electricity charges shall be prepared and submitted to the Commission.
9	A proposal for introducing ToD tariff for LT industrial consumers may be submitted considering the revenue implication and reducing the peak demand.
10	Plan of Energy Audit shall be filed within two months from the date of this order.
11	Preparation and execution of a programme for the repair/replacement of the plants and equipments that useful and efficient lifespan is almost over with the approval of the Commission
12	Board has to provide detailed quantified assessment showing the function wise R&M works necessary and plan for carrying out the same (page 70)
13	Proposals for pension fund and productivity linked employee cost reduction programme to be submitted
14	The Board shall invite proposals from developers of non-conventional energy sources
15	The write off of dues from KWA and others if any shall not be approved unless it is as per the provision of Section 65 of the Act.
	Order on ARR and ERC for FY10-11, Chapter 9, page 113-115
	– Order on ARR and ERC for FY10-11, Chapter 9, page 113-115
1	T&D loss – Separation of Transmission and distribution loss

	– Initiate a study for assessing loss levels in 33kV/11kV system and LT system separately. – Separation of technical and commercial loss
2	Plans for loss reduction to the targeted level by fixing section wise /month wise targets for execution of capital works for loss reduction and faulty meter replacement.
3	Prepare scheme/project wise details with date of commencement, funding pattern, physical and financial progress, target date of completion etc., and submit along with ARR&ERC.
4	For all new projects, an analytical report showing cost and benefit to be furnished.
5	Initiate a work study to assess the reasonable level of employee strength and cost and progress to be intimated in the first week of August 2010.
6	Establish a pension fund and make efforts to reduce pension liabilities immediately. The progress to be intimated in the end of August 2010.
7	The Board to revive the Task Force for overseeing arrear collection and file a first report for the first quarter by 20th of the July 2010.
8	Furnish benchmark Performance parameters for diesel stations for determining the fuel surcharge.
9	Furnish comprehensive proposal for determining the operation norms for generating and transmission system with all supporting details with detailed analysis of actual performance.
10	Prepare a status report on implementation of standards of performance regulation at the circle level and the monitoring mechanism if any.
11	Prepare separate ARR&ERC for each licensed business from 2011-12. The Board shall also propose transmission tariff, SLDC charges, and open access charges along with the ARR for 2011-12.
12	The Board shall study and report the impact of the revised ToD tariff for HTEHT consumers within two months.
13	Prepare an implementation plan including procurement plan for all the important capital projects under generation, transmission and distribution with information to the Commission.
14	File a Proposal for new bill payment mechanism and other customer satisfaction measures within two months.

ANNEXURE VI

COMPARATIVE ANALYSIS OF TARIFF REGULATORY POLICIES

(Historical background of Legislative and Regulatory Initiatives)

1) The Indian Electricity Act, 1910

- Provided basic framework for electric supply industry in India.
- Growth of the sector through licensees. License by State Govt.
- Provision for license for supply of electricity in a specified area.
- Legal framework for laying down of wires and other works.
- Provisions laying down relationship between licensee and consumer

2) The Electricity (Supply) Act, 1948

- Mandated creation of SEBs.
- Need for the State to step in (through SEBs) to extend electrification (so far limited to cities) across the country.
- Main amendments to the Indian Electricity Supply Act
  - Amendment in 1975 to enable generation in Central sector.
  - Amendment to bring in commercial viability in the functioning SEBs – Section 59 amended to make the earning of a minimum return of 3% on fixed assets a statutory requirement (w.e.f 1.4.1985) .
  - Amendment in 1991 to open generation to private sector a establishment of RLDCs.
  - Amendment in 1998 to provide for private sector participation transmission, and also provision relating to Transmission Utilities.

3) The Electricity Regulatory Commission Act, 1998

- Provision for setting up of Central / State Electricity Regulatory Commission with powers to determine tariffs.
- Constitution of SERC optional for States.
- Distancing of Government from tariff determination.

4) The Electricity Act, 2003

- A Central Act
- Old national Acts repealed
  - Indian electricity Act 1910
  - Electricity (supply) Act 1948
  - Electricity Regulatory Commissions Act 1998
- State reform Act provisions to be valid provided they are not inconsistent with the Electricity Act 2003

➔ Hence, the entire Indian electricity sector will be governed by the Electricity Act 2003

- Electricity Act 2003 Emphasis on the following:
  - Breaking monopoly of State Electricity Boards and promoting competition / trading
  - Creating economic imperative for fundamental changes
  - Attracting new investment
  - Reduction of cross-subsidy
  - Competition for increasing efficiency (mostly in generation)

Key Provisions of Electricity Act 2003:

- Defines institutional and policy framework for the whole country
- De-license Generation
- Open Access in Transmission, Distribution

- Promote trading and markets
- De-license rural distribution
- Establishes norms for transparency and public participation
- Re-defined role and mandate of State Governments, Regulators and Licensees
- Establishment of Consumer Grievance Redressal Forums

5) National Electricity Policy 2005

- Emphasises the electricity – development link:

"Electricity is an essential requirement for all facets of our life. It has been recognized as a basic human need. It is a critical infrastructure on which the socio-economic development of the country depends"

- Issues addressed:
    - Rural Electrification
    - Generation , Transmission, Distribution
    - Recovery of Cost of services & Targeted Subsidies.
    - Technology Development and Research and Development (R&D)
    - Competition aimed at Consumer Benefits
    - Financing Power Sector Programmes Including Private Sector Participation.
    - Energy Conservation , Environmental Issues
    - Training and Human Resource Development
    - Cogeneration and Non-Conventional Energy Sources
    - Protection of Consumer interests and Quality Standards
- Generation
    - Power-Demand to be fully met by 2012
    - A part of new generating capacity (say 15%) may be sold outside long term Power Purchase Agreements (PPAs)
- Transmission & Distribution
    - Development of National Grid
    - National and State level Open access to be facilitated
    - Demand side management
- Consumers
    - Access to electricity for all households by 2010
    - 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
    - Cross subsidies to be reduced gradually
    - Provision of support to lifeline consumers (households below poverty line having consumption of 30 units per month) with tariff being at least 50% of average cost of supply.
    - Grievance Forum and Ombudsman to be set up
    - Government and RCs to facilitate capacity building of consumer groups.

6) National Tariff Policy 2006

- Objectives
    - 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

- Covers
  - General approach to tariff
  - Generation, Transmission, Distribution Tariff
  - Trade margin
- Power purchase by DISCOMS to be based on competitive bidding (exception for public sector)
- Cross subsidy surcharge is to be paid by open access consumers. This is calculated as the difference between the consumer tariff and the cost of supply
- Poor consumers (consuming say less than 30 units/month) will get support through cross subsidy. Their tariff will be at least 50% the average cost of supply. SERCs will notify a roadmap to reduce cross subsidy so that by 2011, tariffs would be within +/- 20% the average cost of supply
- Amendment (Mar 08) on Hydro tariff (transparent bidding, long term PPA for 60%, R&R, development fund etc

7) National Rural Electrification Policy

- Goals
  - Provision of access to electricity to all households by year 2009
  - Quality and reliable power supply at reasonable rates
  - Minimum lifeline consumption of 1 unit per household per day as a merit good by year 2012.
- Covers
  - Approach to rural electrification; RGGVY program; Definition of electrified village; Involvement of local community; Financial assistance, Stand-alone systems, Bulk power purchase & management of rural distribution
  - Grid and off grid solutions for Household electrification and economic activities
  - Rural Electrification Corporation to be the nodal agency, Central support to States for RE
  - States to prepare RE Plan, set up District Committees, notify rural areas . SERCs to monitor
  - Franchisees for rural distribution

8) Rural Electrification: Rajiv Gandhi Grameen Vidhyutikaran Yojana (RGGVY) 2005

- Village (1,25,000) and rural household (78 million) electrification
- Central government to provide financial and implementation support to States
- Guarantee by States for minimum 6-8 hours of power supply
- Decentralised Distributed Generation (DDG) to supplement grid power
- US$ 12,500 m outlay

9) Urban Distribution: Re-structured Accelerated Power Development and Reforms Programme (R-APDRP) 2008

- Focus on base line data creation and distribution loss reduction (urban)
- US$ 2500 m for base line data and IT applications
- US$ 10,000 m for distribution strengthening