ABPS INFRASTRUCTURE ADVISORY PRIVATE LIMITED

Draft Approach Paper for

Multi Year Tariff Regulations for FY 2010-11 to FY 2014-15

Submitted to

Maharashtra Electricity Regulatory Commission

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Contents

LIST OF ABBREVIATIONS

AAD	Advance against Depreciation
ABT	Availability Based Tariff
EA 2003	Electricity Act 2003
APR	Annual Performance Review
ARR	Aggregate Revenue Requirement
CBG	Competitive Bidding Guidelines
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
Ckt-Km	Circuit Kilometres
COD	Commercial Operation Date
CPI	Consumer Price Index
CTU	Central Transmission Utility
CUF	Capacity Utilisation Factor
DISCOM	Distribution Companies
FERV	Foreign Exchange Rate Variation
GFA	Gross Fixed Asset
GoM	Government of Maharashtra
IWC	Interest on Working Capital
kWh	kilo Watt hour
MNRE	Ministry of New and Renewable Energy
NEP	National Electricity Policy
TP	Tariff Policy
OA	Open Access
O&M	Operation and Maintenance
PLF	Plant Load Factor
RE	Renewable Energy
RLDC	Regional Load Despatch Centre
ROCE	Return on Capital Employed
ROE	Return on Equity
RPS	Renewable Purchase Specification
R&M	Repair and Maintenance
SEB	State Electricity Board
SERC	State Electricity Regulatory Commission
SLDC	State Load Despatch Centre

STU	State Transmission Utility
ToD	Time of Day
TSU	Transmission System User
UI	Unscheduled Interchange
WPI	Wholesale Price Index

1 Introduction

The Electricity Act, 2003 (EA 2003), as amended in the year 2007 requires the appropriate Commission to be guided by Multi-Year Tariff (MYT) principles while specifying the Terms and Conditions for determination of tariff. Section 61 of the EA 2003 stipulates:

> *"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".(**emphasis added**)*

The Maharashtra Electricity Regulatory Commission (MERC or Commission) notified the Maharashtra Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004 in June 2004, which was superseded by the MERC (Terms and Conditions of Tariff) Regulations, 2005 notified on August 26, 2005 (henceforth 'MERC

Tariff Regulations'). Regulation 14.1 of the MERC Tariff Regulations specified that the first Control Period for the Multi-Year Tariffs would be three financial years beginning April 1, 2006. However, vide its Order dated December 20, 2005, the Commission suspended implementation of the MYT framework by one year and the revised Control Period of three years beginning from April 1, 2007, was specified. The Commission has issued the MYT Order for all the Utilities in the State, except Mula Pravara Electric Cooperative Society (MPECS), in accordance with the MERC Tariff Regulations, for the first Control Period from April 1, 2007 to March 31, 2010.

The prevalent MERC Tariff Regulations were guided by the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004, which specified the norms and approach for tariff determination for Generation Companies and Transmission Licensees regulated by the CERC for the Control Period from April 1, 2004 to March 31, 2009. The Central Electricity Regulatory Commission (CERC) has subsequently notified the CERC (Terms and Conditions of Tariff) Regulations, 2009, which is applicable for the Control Period from April 1, 2010 to March 31, 2015.

The MERC Tariff Regulations do not have any specified applicability period and can theoretically be continued for the next Control Period also. However, subsequent to the notification of the MERC Tariff Regulations, the CERC Tariff Regulations for the Control Period from April 1, 2009 to March 31, 2014 have been notified. Also, the National Electricity Policy and the Tariff Policy have been notified by the Ministry of Power, Government of India, which provide the guidelines for determination of the Revenue Requirement and tariff. Further, the Forum of Regulators (FOR) has also published its Report giving its recommendations on the standard MYT framework to be implemented across the country. Since, in accordance with Section 61 of the EA 2003, the MERC Tariff Regulations have to be guided by all these Notifications and Policies, it is considered necessary to amend the MERC Tariff Regulations for the second Control Period.

Further, during the first Control Period, while issuing the MYT Orders and Annual Performance Review (APR) for the Utilities in the State in accordance with the MERC Tariff Regulations, the Commission has noticed several areas of improvement in the specified MYT framework. The Commission would like to analyse those areas and make necessary modifications to the MERC Tariff Regulations before the next Control Period begins, so that the MYT framework for the next Control Period is in accordance with the modified MYT Regulations.

According to Regulation 14.1 of the MERC Tariff Regulations, the standard Control Period for MYT is five years. Since the first Control Period is ending on March 31, 2010, the next Control Period would begin on April 1, 2010. The Utilities need to submit their MYT Petitions at least 120 days before the beginning of the next Control Period. For Utilities to be able to submit their MYT Petitions in the month of November 2009, it is necessary that the MERC notifies the revised Regulations by September 30, 2009.

In order ensure that the desired objectives are achieved, the Commission engaged the services of ABPS Infrastructure Advisory Private Limited (ABPS Infra) to provide consultancy support to the Commission for development of Multi-Year Tariff Regulations for the second Control Period from FY 2010-11 to FY 2014–15.

The Terms of Reference for this assignment are:

1. Develop Approach Paper on the contours of the Multi-Year Tariff Regulations for the second Control Period of five years beginning April 1, 2010;
2. Formulate the draft MYT Regulations for the second Control Period of five years beginning April 1, 2010
3. Assist the Commission in discussions with the experts,
4. Assist the Commission during subsequent regulatory process.
5. Assist the Commission in finalising the MYT Regulations and Explanatory Memorandum, based on stakeholders' comments and discussions with the MERC.

APBS Infra has drafted this Approach Paper, which is organised in eight Sections as follows:

Section 1: Introduction
Section 2: MYT General Principles
Section 3: Broad Financial Principles
Section 4: Norms and Principles for determination of Revenue Requirement and tariff for Generation Companies

Section 5: Norms and Principles for determination of Revenue Requirement and Transmission Tariff

Section 6: Norms and Principles for determination of Revenue Requirement and Wheeling Charges and Losses for Distribution Wire Business

Section 7: Norms and Principles for determination of Revenue Requirement and Retail Supply Tariff for distribution licensees

Section 8: Norms and Principles for Energy Efficiency (EE) and Demand Side Management (DSM)

2 MYT Overview - General Principles

This Approach Paper details the philosophy and principles for formulation of Regulations for determination of tariff on the basis of Multi-Year Tariff (MYT) principles for the next Control Period of five years from April 1, 2010 to March 31, 2015. The objectives of any MYT framework are:

- Provide regulatory certainty to the investor and consumers by promoting transparency, consistency and predictability of regulatory approach, thereby minimizing the perception of regulatory risk.
- Address the risk sharing mechanism between utility and consumers based on controllable and uncontrollable factors.
- Ensure financial viability of the sector to attract investment, ensure growth and safeguard the interest of the consumers.
- Review operational norms for Generation, Transmission, Distribution and Supply businesses, related issues and recommend suitable measures to address such issues.
- Minimize risks for Utilities and consumers and promote operational efficiency. This will attract investments and would help in bringing greater predictability to consumer tariffs by restricting tariff adjustments to specified indicators.
- Reduce tariffs in the long-term through improvement in operational efficiency.

2.1 Contours of Multi-Year Tariff

2.1.1 Cost plus Regulation vs Performance based Regulations

Historically, the State Government was the owner as well as the Regulator of the power sector in most States, by virtue of being the owner of the vertically integrated State Electricity Boards. Realising the importance of having an independent Regulator of the electricity sector, and in response to the relevant legislation enacted in this regard, most States have established the State Electricity Regulatory Commission to regulate the electricity sector in the respective State, while the Central Government has constituted the Central Electricity Regulatory Commission to regulate the Central sector Utilities as well as inter-State projects.

The SERCs have adopted the approach of 'cost-plus' regulation, whereby tariffs are determined in such a manner so as to enable the Utilities to recover their expenses and earn a pre-determined return on the equity investment or the capital employed. It should be noted that most SERCs do not approve all the expenses, and undertake prudence check on the expenditure with the objective of improving the Utility's efficiency and thereby, reducing tariffs. This introduces an element of 'performance-based' regulation within the overall framework of 'cost-plus' regulation.

The alternative approach to the Cost Plus approach to regulation discussed above, which are followed in India and in other countries, is the Incentive Based Regulation (IBR) or Performance Based Regulation (PBR), as it is commonly known.

Rather than frequent reviews of Utility costs and determining tariffs to reimburse Utilities for what they spend, PBR takes a longer term view and focuses on how Utilities perform. In a well-designed PBR, good performance should lead to higher profits, while poor performance should lead to lower profits. In general, PBR mechanisms provide Utilities with a fixed price or a fixed level of revenues, as opposed to a predetermined level of profits. As a result, Utilities can earn higher, or lower, profits depending upon how efficiently they plan for and operate their systems. The most commonly discussed PBR mechanism is the 'price cap'. Price caps differ from the cost plus approach in two fundamental ways. First, prices are put in place for longer periods of time (e.g., four to six years) as compared to the annual tariff determination usually undertaken under the cost plus approach. The fixed prices over longer periods are intended to provide incentives to reduce costs. Second, Utilities are allowed to lower their prices to some customers, as long as all prices stay within the cap (or caps). This flexibility allows the Utilities to provide competitive price discounts to customers that might otherwise leave their system.

A well-designed price cap scheme begins by setting the initial rates for each customer class fairly, based upon an appropriate allocation of costs. The price cap is then allowed to increase from year to year to allow for inflation, but is also required to decline over time to encourage increased productivity. The controllable component of the regulated tariff is adjusted each year according to predetermined indices in a Price Cap Regulation (PCR). The generic price cap formula can be defined as:

$$\text{Price}_{(t)} \leq \text{Price}_{(t-1)} * [1 + (I - X)] + Z$$

where

$Price_{(t)}$ is the maximum price that can be charged to a customer class or classes for the current period,

$Price_{(t-1)}$ is the average price charged to the same class or classes during the previous period,

I is the inflation factor,

X is the productivity factor, and

Z represents any incremental uncontrollable costs that are not subject to the cap.

PBR mechanisms can also be designed using 'revenue caps' instead of price caps. Revenue caps are based on the same principle as price caps – where the cap in one year is based on the revenue in the previous year with adjustments for inflation and productivity – and can achieve many of the same objectives as price caps. However, revenue caps provide Utilities with significantly different incentives regarding energy efficiency and increased sales. The cost cutting incentives for price and revenue caps are identical. The main difference is that price caps may also encourage increased sales and hence, discourage end-use energy efficiency. With revenue cap approaches, the incentives to invest in energy efficient range from neutral to significant.

2.1.1.1 Need for Price Cap Regulation (PCR)

The common method of regulation followed presently requires the SERCs to review tariffs annually. This engenders a high degree of regulatory uncertainty for the Utilities as well as the consumers. Some income predictability needs to be provided over a certain time-frame (three to five years) for a Utility as well as the consumers to plan effectively and reduce regulatory uncertainty. Internationally, multi-year tariffs are determined for the control period under the (RPI-X+Z) formula, where the tariff in the ensuing year is lower in real terms as compared to the tariff in the current year, after considering the effect of inflation (Retail Price Index – RPI), on account of the efficiency factor 'X' and an uncontrollable pass-through element, viz., 'Z'. Some of the merits of PCR are as under:

- Provides greater regulatory certainty to Investors and consumers.

- PCR helps to align customer and Utility objectives, viz., the customer desires reduction in tariff and certainty in tariff, while the Utility seeks to maximise its returns, which is possible to achieve by increasing operational efficiency, since a large part of the gains will be retained with the Utility.
- PCR can be designed so that cost control and Utility accountability are not jeopardized.
- Quality of service is more directly recognized and rewarded.
- Utilities will be required to provide direct incentives to employees by introducing efficiency gain sharing mechanism, which may act as a stimulus to motivate employees to perform better.
- Improves investment potential in mature Utilities.
- Longer review periods reduce regulatory costs and streamlines the regulatory workload, so that the Regulators can focus on regulating quality of output rather than regulating costs.

However, some of the demerits associated with PCR are as under:

- In a PCR, Utilities may opt to invest less than approved expenditure especially in Capital Expenditure (Capex) and Repair & Maintenance (R&M), which may lead to deterioration of assets. Hence, PCR needs to be accompanied with clearly defined service quality standards as well.
- Normative benchmarks, if not derived properly in PCR may lead to abnormal profits or abnormal losses. Hence, due care needs to be taken while deriving normative benchmark for various parameters considering Utility's past performance as well as best practices in the industry.
- A PCR mechanism designed to achieve any one objective can create incentives that might conflict with other objectives, or even result in unintended consequences. For example, a price cap to promote price stability will create financial disincentives to energy efficiency investments.
- Most PCR mechanisms need to be reviewed over time, to monitor their effectiveness, to assess the impacts on consumers, to prevent unintended outcomes, and to modify where appropriate.

In this context, the FOR Report on MYT framework and distribution margin recommends

> *"6.1.1 Annual revision of performance norms and tariff might not be desirable. During the first control period, which should not be more than three years, the opening levels of performance parameters should be specified as close to the actual level of performance as possible and* ***a trajectory of improvement of norms to desired level be provided with an incentive and disincentive mechanism to share efficiency gains with consumers."***

The FOR Report recommends that the norms for the first Control Period to be specified as close to actual level of performance as possible. FOR Report also emphasises on specifying a trajectory to achieve desired levels of norms, which entails fixing of performance trajectory on normative basis rather than at actual levels for the second Control Period onwards.

Hence, for providing regulatory certainty to consumers and various stakeholders of power sector in Maharashtra, it is proposed that some form of performance based regulations needs to be introduced, and the practice of annual tariff determination be discontinued.

While selecting the appropriate model of PCR, it will be useful to look at the structure of the electricity industry in one such market (Great Britain) and compare it with that prevailing in India.

Electricity Industry Structure in Great Britain (GB)

1. Generation

Traditionally, electricity has been generated by large power stations connected to the transmission system, but in recent years, there has been increased focus upon the deployment of distributed generation (DG). Electricity generation is a competitive activity and there are a number of players that operate in this area of the industry. Hence, generation of electricity is a deregulated activity.

2. Transmission/System Operation (SO)

Once electricity is generated, it is transmitted onto the high voltage electricity transmission network, which is owned by National Grid Electricity Transmission (NGET), Scottish Hydro Electricity Transmission Limited (SHETL) and Scottish Power

Electricity Transmission Limited (SPTL). Despite the disparate ownership of the electricity transmission network, the overall GB system is operated by NGET. NGET has the responsibility for ensuring that the GB electricity transmission network remains in balance and within safe operational limits.

NGET is subject to SO incentive arrangements, under which a target for SO costs, associated with its role as residual balancer and its other SO activities, is set. Under the provisions of the SO incentives, NGET is permitted to retain a proportion of savings against the targets set, but must pay a proportion of any additional costs incurred, in line with the sharing factors agreed.

The costs of providing services that are covered by the regulated price control also include incentives toward efficiency as well as incentives to deliver against a specified quality of service.

3. Distribution of electricity

The electricity distribution networks are medium voltage transportation networks, which are used to carry electricity from the high voltage electricity transmission network to the majority of final customers. In line with the differential voltages for transmission in Scotland as compared with England and Wales, the distribution networks in England and Wales operate at a maximum voltage of 132 kV while the Scottish distribution networks have the potential to operate at a maximum of 66 kV.

There are 14 electricity Distribution Network Operators (DNOs) and these were all historically owned by the Public Electricity Suppliers (PES') at the time of privatisation, who also owned the corresponding supply business in their incumbent supply area. However, since privatisation, there has been significant merger/takeover activity and many of the electricity DNOs are now held within common ownership.

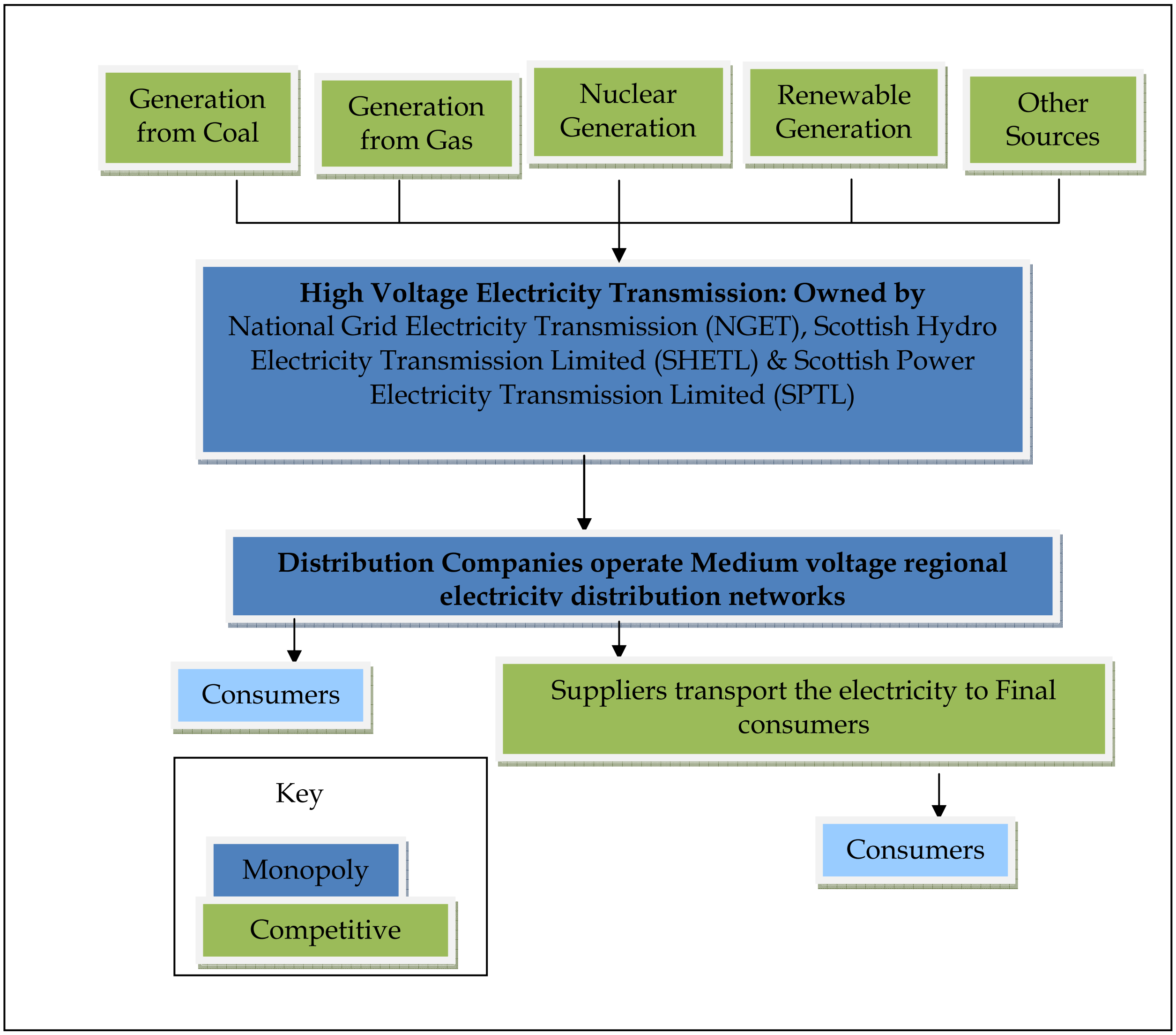
The DNOs, as parties operating on the electricity transmission network, have a role in ensuring that their positions remain in balance and that, in this respect, the volume of electricity that they inject into the system is equivalent to the amount that they draw. The DNOs also have a role in delivering the required capacity to ensure that suppliers can transport electricity to their final consumers. Required revenues are made available to fund the provision of this capacity, via the price control, which incentivises the DNOs to deliver this capacity in the most economic and efficient way.

4. Supply of electricity

At the time of privatisation, each of the PES' held an effective monopoly in the supply of electricity within their respective PES areas and therefore, similarly to British Gas, the PES' were subject to an RPI-X price control. By May 1999, competition had been rolled out at the level of domestic electricity customers, and in April 2002, the supply price controls were lifted, as competition was deemed to have developed sufficiently to protect the interests of consumers. By this point, the domestic market shares of the PES' in their incumbent areas had reduced as a proportion of customer numbers, from an average of 90% in September 1999 to 70% in September 2001. There were also between 12 and 14 suppliers offering domestic tariffs in each of the PES areas. There are currently six large energy supply companies.

Generation tariff and retail tariff are deregulated in electricity industry of Great Britain, which means that there is no price cap for these segments. Only transmission and distribution segments are regulated under price cap mechanism, where regulator regulates the price chargeable to DNOs and Suppliers.

Hence, price cap controls are applicable to distribution and transmission activity in Great Britain. Broad overview of electricity industry structure is shown in the block diagram below:


Generation from Coal
Generation from Gas
Nuclear Generation
Renewable Generation
Other Sources
High Voltage Electricity Transmission: Owned by National Grid Electricity Transmission (NGET), Scottish Hydro Electricity Transmission Limited (SHETL) & Scottish Power Electricity Transmission Limited (SPTL)
Distribution Companies operate Medium voltage regional electricity distribution networks
Consumers
Suppliers transport the electricity to Final consumers
Consumers
Key
Monopoly
Competitive

Selection of Performance Based Regulation Model for Maharashtra

Industry Structure

In the Indian context, generation activity has become partly competitive with introduction of competitive bidding, while transmission is a monopoly activity and distribution is still largely a monopoly despite provisions of open access. All the three segments are regulated by Electricity Regulatory Commissions (ERCs) in India.

PBR Options

PBR mechanisms can be designed in many ways, and can be tailored to achieve many different objectives. PBR mechanisms are frequently thought of as price caps (or revenue caps) designed to encourage regulated Utilities to operate more efficiently and to lower prices over time. However, efficient operation and low costs are not the only objectives of electric utilities and their regulators. ERCs are also concerned about price stability, price equity, reliability, quality of service, promotion of energy efficiency, environmental protection, and more.

Summary of the primary objectives of ERCs and some of the PBR options available to address those objectives are tabulated below:

Table 1 : PBR Options for Meeting Various Regulatory Objectives

Regulatory Objective:	**PBR Structure, Mechanism or Incentive:**
Price stability	Price cap, combination revenue-price cap
Lower prices	Productivity index, base-year price or revenue
Price flexibility	Price cap, revenue cap, combination revenue-price cap
Pricing equity	Price floors, price margins
Durable incentives	Duration of PBR
Improved power plant performance	Targeted incentives, generation price cap
Lower purchased power costs	Price cap, revenue cap, targeted incentives
Balance of shareholder and ratepayer interests	Profit/loss sharing mechanism
Maintain quality of service	Targeted incentives, performance standards

Maintain universal service	Targeted incentives, performance standards
Reliability of supply	Targeted incentives, performance standards
Limit Utility sales promotion	Revenue cap, revenue-price cap
Reduce T&D losses	Price cap, revenue cap, targeted incentives
Improve power quality	Price cap, revenue cap, targeted incentives

In the Indian context, the methods for adopting PBR mechanism are as under:

1. Generation Business: Price cap may be applied to Generation Company as a whole on average generation tariff or Plant-wise or Station-wise caps could be specified under PCR.
2. Transmission Business: Revenue cap on revenue requirement may be applied for the Transmission Utility .
3. Wires Business: Revenue cap on revenue requirement may be applied for the Wires Business
4. Retail Supply Business: Price caps can be applied to customers as a whole, or to individual consumer category. The number of caps specified represents a trade-off for the Regulator between the goal of protecting customers and moving the Utility toward a market driven mechanism. A single cap would allow the Utility maximum flexibility to determine category wise tariff. On the other hand, a cap applied to every customer category would provide greater protection for smaller customers. Moreover, in India, an added complexity to determination of retail tariff is the cross-subsidy element, which has to be gradually reduced in accordance with the EA 2003 and Tariff Policy notified by the Ministry of Power.

   Hence, it is proposed to specify price caps for individual consumer category considering the cross subsidy reduction trajectory.

Productivity Factor

The productivity factor ('X' in RPI – X formula) will have important implications for Utility cost recovery and the rate at which prices are allowed to increase. However, an appropriate level of improved productivity is not easy to define. In most cases, it is based upon historical or projected productivity gains by the Utility and/or by the electricity industry itself. Moreover, a **productivity adjustment may not be necessary if**

the price (or revenue) cap is instead linked directly to input costs determined on the basis of benchmarking with comparable Utilities.

Hence, ABPS Infra is of the opinion that adoption of simple RPI-X+Z mechanism may not be correct choice to make. Instead, a hybrid model needs to be considered, which would typically have some elements of cost-plus mechanism and some elements of RPI-X+Z mechanism, to suit the transitional nature and complexity of Maharashtra's Power Sector.

Hence, it is proposed to specify the performance trajectories for various efficiency parameters for the Generating Companies/Businesses, Transmission Licensees, Wires Business and Retail Supply Business for the second Control Period, based on past performance and desired levels of performance under the MYT Regulations. Based on these norms, Business Plan, and Investment Plan, the Commission would specify the price cap for the first year of the second Control Period and efficiency parameter 'X' for the second Control Period, for the Generating Company in the MYT Order for the second Control Period. Efficiency parameter 'X' for the second Control Period may not be necessary to be specified, if the price cap is derived based on benchmarking of various efficiency parameters with other Utilities of similar profile. Uncontrollable cost (Z) would be passed to consumers on a quarterly basis as an additional charge, which could be positive or negative.

2.2 *Business Plan*

The Forum of Regulators (FOR) in its report on MYT framework and Distribution Margin has recommended as under:

"2.5.4 Distribution licensees should submit the business plan and power purchase plan, for approval of the Commission, at least six months prior to submission of MYT petitions, comprising the following aspects:

- *Category-wise sales projections*
- *Load growth details*
- *Power Procurement Plan from short-term and long-term sources*

- *Details of load shedding*
- *Capital expenditure and capitalisation plans, financing pattern and impact on related expenses*
- *Employee rationalisation*

2.5.5 The Commission should issue its order on the business plan and power procurement plan within four months of submission, so that the licensee submits the MYT petition based on the approved plan"

The MERC Tariff Regulations stipulates as under:

> *"9.1 An application for determination of tariff shall be made to the Commission not less than one hundred and twenty (120) days before the date on which such tariff is intended to be made effective:*
>
> *Provided that the date of receipt of application for the purpose of this Regulation shall be the date of intimation about receipt of a complete application in accordance with Regulation 8.4 above:*
>
> *Provided further that under a multi-year tariff framework,-*
>
> *(i) the application for determination of tariff for any financial year shall be made not less than one hundred and twenty (120) days before the commencement of such financial year;*
>
> *(ii) the application for annual performance review during any financial year of the control period shall be made not less than one hundred and twenty (120) days before the close of such financial year:"*

This effectively requires the Utilities to submit their MYT Petitions on or before 30th November of the previous year for which tariff has to be determined. The FOR recommendations provides for submission of Business Plan six months prior to submission of MYT Petition, i.e., 30th November. Hence, date for submission of Business Plan would be 31st May. However, in the present context, as the date has already passed for the second Control Period, it would be difficult for Utilities to file a Business Plan as per FOR recommended timelines. Hence, it is proposed that Business Plan for the second Control Period may be filed along with the MYT filings for the second Control Period. It is proposed that the Utility shall file the Business Plan for the second Control Period on November 30, 2009 for the Commission's approval, along with the MYT

Petition for the second Control Period. However, for the third Control Period, the timelines recommended by FOR would be applicable.

The Business Plan shall be for a period of five years commencing from FY 2010-11 to FY 2014-15. The Business Plan for the Control Period shall contain the Sales Forecast after considering the effect of proposed load shedding, if any, Power Procurement Plan, employee rationalisation schemes like Voluntary Retirement Schemes, and a Capital investment Plan in accordance with the Commission's directives issued in respect of capital investment programme. The Distribution Licensees should project the power purchase requirement after considering the effect of energy efficiency (EE) and demand side management (DSM) schemes. Also, to the extent practicable, load shedding should be avoided, and the distribution licensees should ensure that adequate capacity is contracted under long-term contracts at optimum prices, to ensure that the consumers are supplied electricity on 24 x 7 basis, and the tariffs are also reasonable.

The Investment Plan shall be a least cost plan for undertaking investments for strengthening and augmentation of the operations of the Utility, as applicable for Generation Companies, Transmission Licensees, and Distribution Licensees. The Investment Plan shall cover all capital expenditure projects of a value exceeding Rs. Ten (10) crore. The Investment Plan shall be accompanied by such information, particulars and documents as may be required for showing the need for the proposed investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the Revenue Requirement and tariffs. A similar dispensation will also be applicable for the Generation Companies (for their Renovation and Modernisation schemes) and Transmission Licensees.

2.2.1 Duration of Multi-Year Tariff Period

The Control Period means a multi-year period typically ranging from 3 to 5 years, fixed by the Commission from time to time for the duration of which, the principles for determination of Aggregate Revenue Requirement (ARR) and tariff will be fixed.

Clause 5.3 (h)(1) of the Tariff Policy notified by the Ministry of Power, Government of India on January 6, 2006 stipulates:

"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."*

Regulation 14.1 of Maharashtra Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2005 notified on August 26, 2005 (henceforth 'MERC Tariff Regulations') stipulates:

" The applicant shall submit a forecast of his aggregate revenue requirement and expected revenue from tariff and charges for the approval of the Commission for each financial year within a control period of five (5) financial years:

Provided that for the first application made to the Commission under this Part, the control period shall be three (3) financial years i.e. April 1, 2006 to March 31, 2009.

Provided further that the Commission may, based on the experience gained with implementation of multi-year tariffs in the State, extend or reduce the duration of subsequent control periods, as it may deem appropriate:

Provided also that the Commission shall not so extend or reduce the duration of subsequent control periods without hearing the parties affected:

Provided also that the Commission shall not extend or curtail the duration of any control period during such control period".

However, vide its Order dated December 20, 2005, MERC suspended implementation of the MYT framework by one year and the revised Control Period of three years beginning from April 1, 2007 was specified. The MERC has issued the MYT Order for all the Utilities in the State, except Mula Pravara Electric Cooperative Society (MPECS), in accordance with the MERC Tariff Regulations, for the first Control Period from April 1, 2007 to March 31, 2010.

Thus, the second Control Period is due to begin on April 1, 2010. Hence, in accordance with the Tariff Policy and considering that the Utilities in the State of Maharashtra have already experienced the first Control Period of three years, it is proposed to have a longer Control Period of five years, over the period from April 1, 2010 to March 31, 2015.

2.2.2 Baseline Values Determination

The baseline data available with the Commission while defining the trajectory of different performance and financial parameters for the Control Period needs to be accurate and reliable. Such baseline data comprises audited accounts of the Utilities, Business Plans filed by the Utilities, and operational and financial parameters of the Utility. The existing performance levels of the Utilities regulated by the Commission also need to be borne in mind while defining the baseline values for the second Control Period. However, ABPS Infra is of the view that benchmarking with its own past performance, and intra- State and inter-State comparison with other comparable Utilities would also need to be undertaken, to encourage Utilities to reduce their costs and achieve normative targets. Each element of Multi-year Tariff determination has been discussed in detail in subsequent sections.

2.3 Revision in Operational Norms

A suitable performance trajectory for improvement in operational parameters has to be evolved along with an appropriate arrangement for sharing the gains and losses on account of superior and inferior performance vis-à-vis target performance, with the consumers. This will ensure protection of consumers' interests as well as provide motivation to the Utilities for improving the efficiency of operations.

While setting the norms, due regard has to be given to the existing performance levels and the desired performance levels, and the performance improvement trajectory has to be designed in such a manner that sufficient time is given to the Utilities to achieve the desired operational efficiency, while at the same time ensuring that the performance trajectory is not slack and is easily achievable by the Utilities. Further, as discussed subsequently in this Approach Paper, there is a mechanism for sharing the gains and losses due to controllable factors vis-à-vis desired operational norms. As a result, the Generating Companies and Licensees are entitled to retain a portion of the gains earned in this manner. However, since one of the basic objectives of the MYT regime is to ensure that the consumer tariffs are reduced in the long-term, the operational norms have to be revised at the beginning of each Control Period, on the basis of the actual performance achieved during the previous Control Period, so that the benefits of operational efficiency improvement are passed on the consumers. Under this mechanism, the Utilities are allowed to retain the incentive earned during the Control Period, and at the end of the Control Period, the operational norms are revised, so that there is continuous improvement and the Utilities are incentivised to further improve their operational efficiency.

2.4 Controllable and Uncontrollable Factors

While formulating the MYT framework, it is essential to clearly specify the controllable factors and uncontrollable factors and their treatment. The impact on the Utility due to uncontrollable factors are generally considered as a pass-through element in tariffs, while the impact – gain or loss – on account of controllable factors has to be shared between the Utility and the consumers in a specified manner.

2.4.1 Controllable factors

Controllable factors are those considered to be under the Utility's control. The Commission needs to define these factors under the MYT framework. The controllable factors are listed below:

1. Capital Expenditure: Change in Capital Expenditure on account of time and/or cost overrun/inefficiencies in the implementation of capital expenditure projects, which are not attributable to an approved change in scope of such project or change in statutory levies or force majeure events, have to be considered as controllable factors, since the Utility is responsible for any delay in the project completion and the impact of the delay in terms of cost should not be passed on to consumers, except in specific circumstances mentioned above.

2. <u>Technical and Commercial losses:</u> The loss reduction trajectory for transmission and distribution licensees would have to be based on the actual performance of the licensees during the present Control Period, and the Business Plan and Investment Plan of the licensee. The actual technical and commercial losses have to be considered as controllable factors, since the transmission and distribution licensees are bound to reduce these losses in accordance with the trajectory specified by the Commission.

3. <u>Operational Parameters</u>: Operational parameters for generation Stations, viz., Availability, Station Heat Rate, Auxiliary consumption, secondary oil consumption, and coal transit losses, are typically considered as controllable factors, as they are within the control of the generating station.

4. <u>Provisioning for Bad Debts:</u> In the electricity supply business, there is an element of bad debt, due to non-payment of electricity bills by the consumers, and the distribution licensee has to make suitable provision for bad debts. However, the distribution licensee has access to the consumers' security deposit, which is collected for precisely this reason. The licensee has to ensure that the collection efficiency is maximized and even the arrears, if any, should be collected. Hence, provisioning for bad debts and collection efficiency are considered as controllable factors.

5. <u>Interest on Working Capital</u>: Working capital expenses are usually allowed on a normative basis, and considered as a controllable factor. Hence, any variation in working capital requirements is not allowed to be passed through to the consumers, and the Utility will be entitled to sharing of gain/loss on account of the variation in actual working capital expenses vis-à-vis normative expenses. In this regard, in case the Utility has not actually incurred any working capital interest expense (as substantiated by documentary evidence of working capital interest payment), then the entire difference between the normative working capital interest and actual working capital interest will be considered as an efficiency gain, and shared between the consumers and Utility. However, if the Utility is able to provide justification in terms of cash flow statements, which show that the Utility has blocked certain funds, which could have been utilised for other purposes, and hence, the actual working capital interest is zero, then the

Commission may be required to consider the 'actual' working capital interest differently.

6. Operation & Maintenance (O&M) Expenses: This comprises employee expenses, Administration & General expenses, and Repair & Maintenance expenses for Generation/Transmission/Wires/Supply businesses. These O&M expenses are well within the control of the Utility's management, and are hence, classified as controllable factors under the MYT framework except in case of some extraordinary circumstances such as increase in O&M expenses due to change in law/statutory provisions, which are considered as uncontrollable expenses.

7. Financing Pattern: This includes the mix of debt and equity, which is usually allowed on normative basis as 70:30. However, the capital cost itself is a controllable factor and has to be approved by the Commission, which will have a bearing on the debt:equity ratio considered by the Commission. Also, financing pattern is relevant in case the Return on Equity approach is adopted for giving returns to the Utility. However, if the Return on Capital Employed (ROCE) approach is adopted for giving returns to the Utility, then there is neither any requirement to specify a normative debt:equity ratio nor consider the financing pattern as a controllable factor. Under the ROCE approach, the Utility would have to take a decision on the best financing mix considering its ability to raise funds through equity and debt and the associated costs.

8. Quality of Supply:

   As mandated under the Tariff Policy, the Commission has to increasingly focus on regulation of the supply quality and service standards, rather than the regulation of costs. The Standards of Performance stipulated by the Commission under its MERC (Standards of Performance of Distribution Licensees, Period for Giving Supply and Determination of Compensation) Regulations, 2005 have to be considered as controllable factors, and any variation from the same has to treated as controllable and sharing of gains/losses has to be undertaken.

   In this context, the FOR Report on MYT framework and distribution margin recommends as under:

"5.4.2 A Composite Index of Supply Availability and Network Availability should be specified. The SERCs should give appropriate weightage to these two factors. Supply availability should be measured on the basis of power contracted by distribution licensees on a long-term basis for the power procurement plan submitted by the utility. Network availability should be measured on the basis of reliability indices such as SAIDI, CAIDI and SAIFI. Feeder Reliability Indices at 11 KV voltage level as specified by CEA would be appropriate till 100% consumer indexing is achieved in the licensee's area as the exact number of effected consumers by any interruption will be known only thereafter. The target achievement for Composite Index of Supply Availability and Network Availability may be specified as 95% for urban areas and 85% for rural areas. ***However, the SERC may initially fix a lower norm for network availability for rural areas keeping in view the present levels of service with trajectory for time bound improvement****.* ***For every 1% under-achievement in composite availability for urban or rural areas, ROE shall be reduced by 0.1% of equity****. The SERC shall specify the mechanism of computing Composite Index of Supply Availability and Network Availability."*

Since, under the proposed framework, the Wires Business and Supply Business are being segregated, the performance indices of both Businesses may be kept separate, rather than determining a Composite Index.

In accordance with the above FOR recommendations, it is proposed that penalty may be imposed on the Supply Licensee for failure to ensure at least 95% supply availability. The RoCE will be reduced by 0.1% for every 1% under-achievement of supply availability below 95%.

9. Power Purchase Expenses:

During the public regulatory process on the Annual Performance Review (APR) of different distribution licensees for FY 2008-09, several objectors contended that the increase in power purchase cost due to costly power purchase from external sources should be treated as controllable expenditure, and certain portion of the cost of purchase from other sources on short-term basis should be borne by the Distribution Licensee, rather than being entirely passed through to the consumers, in a manner similar to that adopted for other controllable expenses such as Operation & Maintenance (O&M) expenses, etc. The Commission has stated in the APR Order of

RInfra-D for FY 2008-09 that there is merit in the suggestions of the objectors, given that the Commission has given repeated directives to all the distribution licensees to enter into long-term contracts for their power purchase requirement, at reasonable rates, rather than relying on costly short-term sources.

MERC (General Conditions of Distribution Licence) Regulations, 2006 states

*"**8.3. FUNCTIONS / ACTIVITIES OF THE DISTRIBUTION LICENSEE***

*8.3.1 **The Distribution Licensee shall develop and maintain an efficient**, safe, coordinated and **economical distribution system in the Area of Supply** and effect safe supply of electricity to consumers in such area in accordance with the provisions of the Act, Rules, Regulations, Orders and directions of the Commission.*

*8.3.2 **The Distribution Licensee shall take all reasonable steps to ensure that all consumers** connected to the Distribution Licensee's Distribution System **receive supply of electricity as provided in the Standards of Performance Regulations,** and other guidelines issued by the Commission in accordance with the provisions of the Act, Rules and Regulations issued there under and shall on the application of the owner or occupier of any premises within the Area of Supply, give connection to the electricity to such premises.*

Provided that the Distribution Licensee shall duly comply with the Standards as the Commission may specify from time to time, for the performance of duties of the Distribution Licensees under the Act.

*8.3.3 After seeking prior approval of the Commission, **the Distribution Licensee shall purchase electricity from generating companies or licensees or from other sources through agreements for purchase of power for distribution and supply within the area of supply and for meeting the obligations under the Licence and under the provisions of the Act, provided that such procurement shall be made in an economical manner** and under a transparent power purchase and procurement process which shall be required to be in accordance with the regulations, guidelines, directions made by the Commission from time to time."*

Hence, one of the most important responsibilities and duties of the Distribution Licensee, as defined in conditions of distribution licence, is to provide continuous supply of electricity (on a 24x7 basis) in an economical manner, which entails procuring sufficient quantum of power at most optimum rates. The proportion of short-term power procured by various distribution licensees is shown in the Table below:

Particulars		Power Purchase			Percentage of total power purchase
		MU	Rs Crore	Rs/kWh	%
FY 2008-09	**RInfra-D**				
	Long-term Power Purchase	6,852	2,586	3.77	72.02%
	Short-term Power Purchase	2,662	2,385	8.96	27.98%
	Total	9,514	4,971	5.22	
FY 2008-09	**BEST**				
	Long-term Power Purchase	4,715	2,369	5.02	98.28%
	Short-term Power Purchase	83	67	8.12	1.72%
	Total	4,798	2,436	5.08	
FY 2008-09	**TPC-D**				
	Long-term Power Purchase	2,457	1,042	4.24	92.67%
	Short-term Power Purchase	194	167	8.58	7.33%
	Total	2,651	1,209	4.56	
FY 2007-08	**MSEDCL**				
	Long-term Power Purchase	76223	14233	1.87	98.38%
	Short-term Power Purchase	1256	730	5.81	1.62%
	Total	77479	14963	1.93	

Note: Figures are taken from latest Tariff Orders of RInfra-D, TPC-D and BEST. For MSEDCL, figures are taken from the Tariff Order dated June 20, 2008.

Summary of the objections raised by consumers and consumer representatives in the Tariff determination process of RInfra-D for APR of FY 2008-09 in the context of high cost of power purchase:

1. Shri Ashok Pendse of Mumbai Grahak Panchayat (MGP), one of the authorised Consumer Representatives, submitted that the average power purchase rate was

Rs. 3.17 per unit, Rs. 4.38 per unit, and Rs. 6.39 per unit for FY 2006-07, FY 2007-08, and FY 2008-09, respectively, and RInfra-D has projected the average power purchase expense as Rs. 5.60 per unit for FY 2009-10. He submitted that there should be reduction in power purchase cost for FY 2009-10 on the account of reduction in fuel cost. He also submitted that it is essential that the licensee should procure power through long-term PPAs and visible efforts should be made for procuring power through competitive bidding. He added that the distribution licensee is responsible for not contracting for adequate quantum of power on long-term basis, which has increased the cost of power purchase, and hence, there should be some sharing mechanism, whereby the additional cost due to costly power purchase is not passed on entirely to the consumers, and the distribution licensee has to share some of the burden on this account.

2. Shri Shantanu Dixit, one of the authorised Consumer Representatives, submitted that in the APR Petition submitted last year, RInfra-D stated that the bilateral power purchase for FY 2007-08 and FY 2008-09 forms only 5-7% of the energy input requirement and the power procured so far has been at various rates ranging from Rs. 3.97/kWh to Rs. 5.51/kWh.

Table: Source-wise average cost and share of power procured

Source	FY 07	FY 08	FY 09	FY 10
DTPS	**2.01 (48%)**	**2.13 (44%)**	**2.45 (41%)**	**2.65 (39%)**
TPC-G	**3.02 (51%)**	**4.02 (50%)**	**4.83 (30%)**	**3.82 (30%)**
RPO	**0.00 (0%)**	**3.49 (0%)**	**3.50 (0%)**	**3.65 (2%)**
Bilateral	**4.39 (1%)**	**5.49 (5%)**	**8.77 (20%)**	**7.00 (29%)**
Imbalance Pool	**7.13 (0%)**	**5.69 (1%)**	**9.45 (8%)**	**0.00**

Shri. Dixit submitted that during FY 2008-09, RInfra-D has purchased 20% of the total input from bilateral sources at an average cost of Rs. 8.77 per unit and further, for FY 2009-10, they have estimated that 29% of the total quantum of power will be purchased from bilateral sources at an average cost of Rs. 7.00 per unit, which will result in placing a high tariff burden on the consumers. In spite of being aware about the likely shortage, since the past 6 years, RInfra-D has not entered into any long or even medium term power purchase agreement with any new supplier/source.

Shri. Dixit submitted that in the Order dated January 4, 2008 for RInfra-D, the Commission has ruled as under:

> "*licensees should not seek post facto approval for power procurement that has been undertaken on account of inadequate planning and demand assessment*."
>
> "*Thus, the licensee should be financially and legally penalized for failure to ensure cost effective power procurement on timely basis.*"

As clear from the above discussion, while RInfra-D has a very high proportion of costly power, there is no planned load shedding in RInfra-D licence area. On the other hand, MSEDCL is procuring a very small quantum of costly power; however, the load shedding in MSEDCL licence area is very severe. Thus, unless the distribution licensees enter into long-term contracts at appropriate rates for the required quantum of power, there will always be a trade-off between shedding load or procuring costly power to mitigate the load shedding, which will result in higher tariffs.

Since, power purchase was earlier categorised as an uncontrollable parameter, there is no real pressure on the distribution licensees to procure cheaper power. If the wires business and supply business is segregated, one of the prime differentiating factors between various suppliers would be the ability to source cheaper power, which can only be achieved through long-term power purchase. Moreover, consumers should not be burdened with the inefficiency of the supplier to fulfil its basic function, and **it proposed that a maximum of 5% of total power requirement can be procured through short-term contracts.**

While deciding on the controllable factors as discussed above, there are certain aspects on account of which, it is possible that certain factors could be considered as uncontrollable, as discussed below:

a) **Transit loss in procurement of coal by generating stations:** Very often, the generating Companies submit that they have no control over the transit losses that occur outside the premises of the generating station, as the coal is transported through open wagons and the Railways insist on coal weighment at the loading point rather than the receiving point, and all losses due to theft, pilferage, and moisture losses have to be borne by the generating Station, since the Railways do not give any guarantee for the quantity of coal delivered. While this is partly correct, experience of generating stations in several States shows that transit losses can be minimized with adequate efforts of joint weighment, and ensuring electronic weighbridges at the coal loading point, apart from taking up the issue with the Railways. Hence, it is proposed to consider coal transit losses as a controllable factor.

b) Capital Cost over-run due to delay by equipment supplier: Sometimes, the Generating Companies submit that time and cost over-run incurred while setting up new generation facilities is on account of delays in delivery of the equipment by the equipment supplier and hence, the impact of such delays should be considered as an uncontrollable factor. In this context, the Generating Companies should ensure that the contract for procurement of equipment is drafted in such a manner that there are adequate safeguards to protect the Utility from incurring losses due to the delay in supply of equipment. Since this is a contractual matter, and considering that it would be difficult for the Commission to establish whether the delay is on account of delay in equipment supply or due to some delay on the part of the Generating Company, which is often a matter which goes for arbitration, it is proposed to consider the impact of time and cost-overrun in capital expenditure projects as a controllable factor, irrespective of whether the delay is attributed to delay in equipment supply or otherwise.

c) Variation in employee expenses due to wage revision: Utilities enter into wage agreements with their employees, which are usually valid for a period of four to five years. Since O&M expenses, which include employee expenses, are expected to be allowed on a normative basis, there would be a need to factor in the impact of the wage agreement while determining the norm for O&M expenses. At the same time, it needs to be ensured that wage agreements are co-related with performance improvements and the scale of operations of the Utility, so that there is no significant difference vis-à-vis the norms determined by the Commission.

d) Interest Expenses: In this context, it should be understood that interest expenses are to be considered as an uncontrollable factor only under the RoE approach for computing return, since under the ROCE approach, the Utility has to optimise the financing mix.

2.4.2 Uncontrollable factors

Z-factors: RPI-X+Z mechanism allows for recovery of specific costs that are not meant to be subject to the price cap. Z-factors usually include costs over which the Utility has no control, such as fuel cost variation, etc. They also include costs that are not meant to be subject to cost-cutting pressures, such as Demand Side Management (DSM) related expenses. The costs that are chosen to be recovered through the Z-factor can have important planning implications.

Uncontrollable factors are those factors, which are beyond the control of the Utility.

Clause 4.5 (h)(4) of the Tariff Policy stipulates:

> *"Uncontrollable costs should be recovered speedily to ensure that future consumers are not burdened with past costs. Uncontrollable costs would include (but not limited to) fuel costs, costs on account of inflation, taxes and cess, variations in power purchase unit costs including on account of hydro-thermal mix in case of adverse natural events."*

The uncontrollable factors are:

1. Force Majeure events, such as acts of war, fire, natural calamities, etc.
2. Change in law, judicial pronouncements, and Orders of the Central Government, State Government or Commission
3. Economy wide influences such as unforeseen changes in inflation rate, taxes and statutory levies
4. Variation in fuel cost on account of variation in coal, oil and all primary/secondary fuel prices.
5. Variation in power purchase expenses for the distribution licensees.
6. Variation in freight rates

7. Variation on account of change in hydro-thermal mix due to adverse natural events
8. Variation in number or mix of consumers or quantities of electricity supplied to the consumers

2.5 Sharing of Gains and losses

In this Section, the mechanism of sharing the gains and losses on account of controllable factors has been elaborated. The variation in expenses and revenue on account of uncontrollable factors will have to be passed through to the consumers periodically, through the 'Z' factor.

Clause 8.1 (2) of the Tariff Policy stipulates:

> *"The State Commissions should introduce mechanisms for sharing of excess profits and losses with the consumers as part of the overall MYT framework. In the first control period the incentives for the utilities may be asymmetric with the percentage of the excess profits being retained by the utility set at higher levels than the percentage of losses to be borne by the utility. This is necessary to accelerate performance improvement and reduction in losses and will be in the long term interest of consumers by way of lower tariffs."*

The Profit Sharing mechanism is intended to share the benefits of better performance of the Utility with the consumers, while at the same time ensuring that the Utility has enough incentive to improve its operational efficiency. The proposed sharing of gains and losses in case of controllable factors is discussed below:

2.5.1 Sharing of gains or losses on account of controllable factors

The MERC Tariff Regulations provides for sharing of aggregate gain to the Generating Company or Licensee on account of controllable factors as under:

> *"19.1 The approved aggregate gain to the Generating Company or Licensee on account of controllable factors shall be dealt with in the following manner:*

(a) One-third of the amount of such gain shall be passed on as a rebate in tariffs over such period as may be specified in the Order of the Commission under Regulation 17.10;

(b) In case of a Licensee, one-third of the amount of such gain shall be retained in a special reserve for the purpose of absorbing the impact of any future losses on account of controllable factors under clause (b) of Regulation 19.2; and

(c) The balance amount of gain may be utilized at the discretion of the Generating Company or Licensee.

19.2 The approved aggregate loss to the Generating Company or Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such loss may be passed on as an additional charge in tariffs over such period as may be specified in the Order of the Commission under Regulation 17.10; and

(b) The balance amount of loss shall be absorbed by the Generating Company or Licensee."

In this context, the FOR Report on MYT framework and distribution margin has recommended as under:

"6.2 Sharing of benefits of efficiency gains with consumers

6.2.1

The losses on account of under achievement in controllable parameters shall not be shared with consumers as norms are being fixed at close to actual levels, except in extraordinary circumstances if decided by the SERC.

6.2.2

Efficiency gains with respect to controllable parameters shall be shared between the licensee and the consumer in the ratio of two-third and one-third at the end of every year during the truing up exercise."

Hence, it is proposed to adopt the FOR recommendation, and sharing of efficiency losses is not being proposed under the MYT Regulations. The ratio for sharing the gains may be as under:

a. In case of Generation Company and Licensees, one-third of such gain may be passed on to the consumers as a rebate in tariffs over a period of time as may be specified by the Commission

b. The balance amount, which will amount to two-thirds of such gain for generation Companies and licensees, may be utilized by the Utility at its discretion.

On the other hand, the approved aggregate loss to the Generating Company or the Licensee on account of controllable factors needs to be borne by Generating Company or the Licensee.

2.5.2 Mechanism for pass through of gains or losses on account of uncontrollable factors

The MERC Tariff Regulations provides for pass through of aggregate gain or losses to the Generating Company or Licensee on account of uncontrollable factors as under:

> *"18.1 The approved aggregate gain or loss to the Generating Company or Licensee on account of uncontrollable factors shall be passed through as an adjustment in the tariff of the Generating Company or Licensee over such period as may be specified in the Order of the Commission passed under Regulation 17.10:"*

In this context, the FOR Report on MYT framework and distribution margin has recommended as under:

> *"6.2.3*
>
> *The entire gains and losses on account of uncontrollable factors shall be passed on to consumers during the truing up process."*

Hence, it is proposed to adopt the FOR recommendations in this regard, and the gain or loss to the Generating Company or Licensee on account of uncontrollable factors shall be passed through as an adjustment in the tariff of the Generating Company or Licensee on a quarterly basis through the 'Z' factor.

2.6 *Performance Review and Truing Up*

During the first MYT Control Period of three years from FY 2007-08 to FY 2009-10, Annual Performance Review (APR) of a Generating Company/Licensee has been undertaken by the Commission. In accordance with the MERC Tariff Regulations, the provisional truing up of current year, and final truing up of the previous year's expenses and revenue is undertaken, while determining the annual tariff for the ensuing year. However, annual truing up and tariff determination defeats the very purpose of Multi Year Tariff framework. It is observed that Utilities tend to revise their estimates of sales, expenses and revenue for every year of the Control Period.. During the public regulatory process on the APR Petitions for FY 2008-09, several consumers have expressed their opinion that revising tariff on an annual basis is against the principles of MYT. While this is not incorrect if one goes by the pure concept of MYT, in Maharashtra, parameters like sales and power purchase have not been stipulated in the MYT Orders, due to the uncertainty on account of the prevailing supply shortages in the State and the respective licence area. Consequently, the tariff has been specified for only one year, rather than the Control Period, which is also in accordance with the MERC Tariff Regulations, which specifies that tariff, will be determined annually.

Consequently, in the MYT Orders, the Commission has primarily stipulated the following parameters separately for each year of the Control Period, viz.,

(a) <u>Performance trajectory</u>

i. Station Heat Rate (SHR), auxiliary consumption, transit losses and secondary oil consumption for Generating Companies;

ii. Availability for Transmission Licensees; and

iii. Distribution loss for Distribution Licensees

(b) <u>Cost elements</u>

i. Operation & Maintenance (O&M) expenses have been approved as a whole for Generating Companies, and for individual elements, viz., employee expenses, A&G expenses, and R&M expenses, for Transmission Licensees and Distribution Licensees

ii. Interest on Working capital

It is observed that the annual review process requires very high regulatory oversight and is very time-consuming and is almost equal and some-times more strenuous than the earlier approach of annual tariff determination.

Also, the losses on account of controllable factors are not proposed to be a pass through as explained earlier in this Section and hence, ABPS Infra proposes that review of performance of Utilities shall be undertaken at the end of the Control Period.

2.7 Applicability of MYT Regulations

The MYT Regulations shall extend to the whole of the State of Maharashtra. These Regulations shall be applicable for determination of tariff in all cases covered under these Regulations from FY 2010-11, i.e., April 1, 2010 and onwards up to FY 2014-15, i.e. March 31, 2015. However, for all purposes including the review matters pertaining to the period till FY 2009-10, the issues related to determination of tariff shall be governed by MERC (Terms and Conditions of Tariff) Regulations, 2005, including amendments thereto.

3 Broad Financial Principles

The broad financial principles envisaged under the MYT framework proposed for the second Control Period from FY 2010-11 to FY 2014-15 in the State of Maharashtra have been discussed in this Section. These broad financial principles are required to be specified for the State of Maharashtra considering various factors such as investments required in the sector, risks involved in the sector, sector structure, extent of private participation in the sector, investments that have materialized in the sector in the recent past, etc.

The existing MERC (Terms and Conditions of Tariff) Regulations, 2005 also address the broad financial principles. However, these financial principles need to be revisited while establishing the Multi-year Tariff framework for the second Control Period, in view of the developments subsequent to the notification of the above-said MERC Tariff Regulations. The broad financial principles discussed in this Section are:

- Approach for Giving Returns – Equity or Capital Employed
- Capital Cost
- Depreciation
- Interest on Working Capital
- Deposit works, consumer contribution and grants

3.1 Approach for Giving Returns

In any business, in addition to recovery of the costs incurred, the investors are entitled to earn an appropriate return on their investment, since there are alternative investment opportunities, and the investor has to choose between these alternative investment opportunities, in view of his risk-return profile.

The Rate Base is defined as the Capital Base on which the rate of return is applied to compute the permissible return to the investors. There are two Options for considering the Rate Base, viz.,

- Return on Equity (ROE) approach, where the Rate Base is equal to the equity or the networth invested in the business,
- Return on Capital Employed (ROCE) approach, where the Rate Base is the total capital employed (Equity and Debt) by the Utility.

3.1.1 Merits and Demerits of ROE approach

The ROE approach has been preferred by the CERC as well as majority of SERCs, as it is a simple approach to understand and adopt; the return is computed on the equity approved by Commission. If the actual equity infusion is higher than the normative level, then the return is computed on the normative equity level. However, in case the actual equity infused is below normative level, the actual equity infused is used to compute return on equity. The rate base is computed by applying the debt:equity mix to the approved capital cost of project.

The merits of ROE approach are:

i) It is easy to compute and simple to implement, and is hence, easily understood by all stakeholders.

ii) The investor gets assured returns on equity investment for ever, once the investment is done.

iii) The Utility is protected against the risk of fluctuation of interest rates, since interest expense is allowed as a pass through expense at actuals.

The demerits of ROE approach are:

i) No incentives for companies to bring down cost of capital, as return on equity invested is guaranteed and actual interest expenses expenditure incurred is also pass through.

ii) Utilities are not encouraged to practice financial engineering and optimise the financing mix by restructuring debt and equity, since the debt:equity ratio is allowed on normative basis (usually 70:30)

iii) Utilities may tend to inject more equity and try to reach normative equity allowed in order to maximize their profits, which in turn results in higher cost of capital.

iv) Even if assets are depreciated fully, Utilities get assured return on equity invested.

v) In case the equity on the Balance Sheet of the Utility is low, which is the case with quite a few State-owned Utilities as they have been largely funded through loans, then the resultant claim for RoE is also reduced, which may hamper the Utility's efforts to invest in future capital expenditure.

3.1.2 Merits and Demerits of ROCE approach

The merits of ROCE approach are:

i) The ROCE approach incentivises financial planning to optimize the debt-equity mix and bring down the cost of capital.

ii) This approach recognises that the consumers should pay for the capital employed to fund the assets used to serve the consumers.

iii) The consumers are insulated from changes in debt-equity mix and changing interest rates, etc.

iv) It also makes it easier for the Regulators as they do not have to monitor debt and equity component separately.

v) Since the returns are linked to the investment in the business, once the asset is fully depreciated, then the Utility does not earn any return on its investment, and hence, the tariffs would also reduce to that extent.

vi) State-owned Utilities, which may have a lower equity base, would not be adversely affected, since the Returns would be given on the total capital employed, rather than the equity invested in the business.

The demerits of ROCE approach are:

i) The ROCE approach requires an estimation of the normative cost of debt and benchmarking of the debt-equity ratio, which could lead to windfall profits or abnormal losses depending on the ability of the Utility to undertake financial engineering to restructure its debt and equity.

ii) The Public Sector entities may find it difficult to manage the inherent risks under the ROCE approach.

iii) The ROCE approach may also pose an entry barrier for new entrants as they may not be able to achieve the desired debt:equity mix and also may not be able to source cheaper loans, as compared to existing companies with stronger Balance Sheet.

The Commission has adopted the RoE approach while formulating the MERC Tariff Regulations, which stipulates as under:

1.<u>Generation Business</u>

"31.1.1 For the purpose of these Regulations, the amount of loan capital and equity capital shall be calculated as follows: (b) The amount of equity capital shall be equal to-

(i) equity capital as at April 1, 2004 as determined by the Commission in accordance with the Explanation below; plus

(ii) equity component of approved capital expenditure for the financial year ending March 31, 2005:

Provided that in case of a Generating Company formed as a result of a transfer scheme under Section 131 of the Act, the date of the said transfer scheme shall be the effective date instead of April 1, 2004 for determination of equity capital under clause (b) above.

Explanation – for the purpose of this Regulation, equity capital shall be the sum total of paid-up equity capital, preference share capital, fully / compulsorily convertible debentures (or other financial instruments with equivalent characteristics), foreign currency convertible bonds, share premium account and any reserves, available for distribution as dividend or for capitalization by way of issue of bonus shares, which have been invested in the Generation Business. The amount of any grant, revaluation reserve, development reserve, contingency reserve and contributions from customers shall not be included in the equity capital. The amount reflected in the books of account as deferred tax liability or deferred tax asset of the Generation Business shall be added or deducted, as the case may be, from the amount of equity capital.

…

34.1 Return on Equity

Return on equity capital shall be computed on the equity capital determined in accordance with Regulation 31 at the rate of 14 per cent per annum in Indian Rupee terms."

2. Transmission Business

"50.1 Return on equity capital

50.1.1 The Transmission Licensee shall be allowed a return at the rate of 14 per cent per annum, in Indian Rupee terms, on the amount of approved equity capital:

Explanation I – for the purpose of this Regulation, equity capital shall be the sum total of paid-up equity capital, preference share capital, fully /compulsorily convertible debentures (or other financial instruments with equivalent characteristics), foreign currency convertible bonds, share premium account and any reserves, available for distribution as dividend or for capitalization by way of issue of bonus shares, which have been invested in the Transmission Business. The amount of any grant, revaluation reserve, development reserve, contingency reserve and contributions from users shall not be included in the equity capital.

The amount reflected in the books of account as deferred tax liability or deferred tax asset of the Transmission Business shall be added or deducted, as the case may be, from the amount of equity capital

Explanation II – for the purpose of this Regulation, the amount of equity capital as at April 1, 2005 shall be computed as follows:

Equity capital as at April 1, 2004 as determined by the Commission in accordance with Explanation I above, plus

Equity capital portion of the allowable capital cost, for the investments put to use in transmission business, calculated in accordance with Regulation 46 and Regulation 47 above, for the year ending March 31, 2005:

Provided that in case of a Transmission Licensee formed as a result of a transfer scheme under Section 131 of the Act, the date of the said transfer scheme shall be the effective date instead of April 1, 2004 for determination of equity capital above.

The amount of equity capital at the commencement of each financial year thereafter shall be computed as follows:

Equity capital as at the commencement of the previous financial year, calculated in accordance with these Regulations, plus

Equity capital portion of the allowable capital cost, for the investments put to use in transmission business, calculated in accordance with Regulation 46 and Regulation 47 above, for the previous financial year.

50.1.2 The return on equity capital shall be computed in the following manner:

(a) Return at the allowable rate as per Regulation 50.1.1 above, applied on the amount of equity capital at the commencement of the financial year; plus

(b) Return at the allowable rate as per Regulation 50.1.1 above, applied on 50 per cent of the equity capital portion of the allowable capital cost, for the investments put to use in transmission business, calculated in accordance with Regulation 46 and Regulation 47 above, for such financial year.

50.1.3 Any over-recovery or under-recovery of return on equity capital on account of variations in the annual allowable capital cost from the approved level shall be attributed to the same controllable or uncontrollable factors as have resulted in such capital cost variations."

3.<u>Wheeling Business</u>

"63.1 Return on equity capital

63.1.1 The Distribution Licensee shall be allowed a return at the rate of 16 per cent per annum, in Indian Rupee terms, on the amount of approved equity capital:

Explanation I – for the purpose of this Regulation, equity capital shall be the sum total of paid-up equity capital, preference share capital, fully /compulsorily convertible debentures (or other financial instrument with equivalent characteristics), foreign currency convertible bonds, share premium account and any reserves, available for distribution as dividend or for capitalization by way of issue of bonus shares, which have been invested in the Distribution Business. The amount of any grant, revaluation reserve, development reserve, contingency reserve and contribution from users shall not be included in the equity capital. The amount reflected in the books of account as deferred tax liability or deferred tax asset of the Distribution Business shall be added or deducted, as the case may be, from the amount of equity capital.

Explanation II – for the purpose of this Regulation, the amount of equity capital as at April 1, 2005 shall be computed as follows:

Equity capital as at April 1, 2004 as determined by the Commission, in accordance with Explanation I above, plus

Equity capital portion of the allowable capital cost, for the investments put to use in distribution business, calculated in accordance with Regulation 60 and Regulation 61 above, for the year ending March 31, 2005:

Provided that in case of a Distribution Licensee formed as a result of a transfer scheme under Section 131 of the Act, the date of the said transfer scheme shall be the effective date instead of April 1, 2004 for determination of equity capital above.

The amount of equity capital at the commencement of each financial year thereafter shall be computed as follows:

Equity capital as at the commencement of the previous financial year, calculated in accordance with these Regulations, plus

Equity capital portion of the allowable capital cost, for the investments put to use in distribution business, calculated in accordance with Regulation 60 and Regulation 61 above, for the previous financial year.

63.1.2 The return on equity capital shall be computed in the following manner:

(a) Return at the allowable rate as per Regulation 63.1.1 above, applied on the amount of equity capital at the commencement of the financial year; plus

(b) Return at the allowable rate as per Regulation 63.1.1 above, applied on 50 per cent of the equity capital portion of the allowable capital cost, for the investments put to use in distribution business, calculated in accordance with Regulation 60 and Regulation 61 above, for such financial year.

63.1.3 Any over-recovery or under-recovery of return on equity capital on account of variations in the annual allowable capital cost from the approved level shall be attributed to the same controllable or uncontrollable factors as have resulted in such capital cost variations."

4.Retail Sale of Electricity

"76.1 Return on equity capital

76.1.1 The Distribution Licensee shall be allowed a return at the rate of 16 per cent per annum, in Indian Rupee terms, on the amount of approved equity capital:

Explanation I – for the purpose of this Regulation, equity capital shall be the sum total of paid-up equity capital, preference share capital, fully / compulsorily convertible debentures (or other financial instrument with equivalent characteristics), foreign currency convertible bonds, share premium account and any reserves, available for distribution as dividend or for capitalization by way of issue of bonus shares, which have been invested in the Distribution Business and in the Retail Supply Business. The amount of any grant, revaluation reserve, development reserve, contingency reserve and contributions from consumers / users shall not be included in the equity capital. The amount reflected in the books of account as deferred tax liability or deferred tax asset of the Distribution Business and the Retail Supply Business shall be added or deducted, as the case may be, from the amount of equity capital

Explanation II – for the purpose of this Regulation, the amount of equity capital as at April 1, 2005 shall be computed as follows:

Equity capital as at April 1, 2004 as determined by the Commission in accordance with Explanation I above, plus

Equity capital portion of the allowable capital cost, for the investments put to use in distribution business, calculated in accordance with Regulations 72 and 73 above, for the year ending March 31, 2005:

Provided that in case of a Distribution Licensee formed as a result of a transfer scheme under Section 131 of the Act, the date of the said transfer scheme shall be the effective date instead of April 1, 2004 for determination of equity capital above:

Provided further that in case of a local authority engaged, before the commencement of the Act, in the business of distribution of electricity, the opening balance of equity capital shall be stipulated appropriately by the Commission in its Order passed under sub-section (3) of Section 64 of the Act.

The amount of equity capital at the commencement of each financial year thereafter shall be computed as follows:

Equity capital as at the commencement of the previous financial year, calculated in accordance with these Regulations, plus

Equity capital portion of the allowable capital cost, for the investments put to use in distribution business, calculated in accordance with Regulations 72 and 73 above, for the previous financial year.

76.1.2 The return on equity capital shall be computed in the following manner:

(a) Return at the allowable rate as per Regulation 76.1.1 above, applied on the amount of equity capital at the commencement of the financial year; plus

(b) Return at the allowable rate as per Regulation 76.1.1 above, applied on 50 per cent of the equity capital portion of the annual allowable capital cost, for the investments put to use in distribution business, calculated in accordance with Regulation 72 and Regulation 73 above, for such financial year.

76.1.3 Any over-recovery or under-recovery of return on equity capital on account of variations in the annual allowable capital cost from the approved level shall be attributed to the same controllable or uncontrollable factors as have resulted in such capital cost variations."

In this context, Clause 5(a) of the Tariff Policy notified on January 6, 2006 stipulates:

"Balance needs to be maintained between the interests of consumers and the need for investments while laying down rate of return. Return should attract investments at par with, if not in preference to, other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector.

The Central Commission would notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital which shall be followed by the SERCs also. The rate of return notified by CERC for transmission may be adopted by the State Electricity Regulatory Commissions (SERCs) for distribution with appropriate modification taking into view the higher risks involved. For uniform approach in this matter, it would be desirable to arrive at a consensus through the Forum of Regulators.

While allowing the total capital cost of the project, the Appropriate Commission would ensure that these are reasonable and to achieve this objective, requisite benchmarks on capital costs should be evolved by the Regulatory Commissions.

Explanation: For the purposes of return on equity, any cash resources available to the company from its share premium account or from its internal resources that are used to fund the equity commitments of the project under consideration should be treated as equity subject to limitations contained in (b) below.

The Central Commission may adopt the alternative approach of regulating through return on capital.

The Central Commission may adopt either Return on Equity approach or Return on Capital approach whichever is considered better in the interest of the consumers.

The State Commission may consider 'distribution margin' as basis for allowing returns in distribution business at an appropriate time. The Forum of Regulators should evolve a comprehensive approach on "distribution margin" within one year. The considerations while preparing such an approach would, inter-alia, include issues such as reduction in Aggregate Technical and Commercial losses, improving the standards of performance and reduction in cost of supply."

CERC, in its Approach Paper, published along with the draft Tariff Regulations for the Control Period from FY 2009-10 to FY 2013-14, has stated:

"The Commission, while framing regulations for the previous periods, had recognized that Return ***on Capital Employed (RoCE) approach is preferable but because of lack of benchmarking for Debt-Equity mix, fluid situation in regard to interest rate and debt market in India, had decided to adopt Return on Equity (RoE) approach.*** *With the listing of major power utilities on stock exchanges, permission for 100% FDI in power sector, development of debt market in India, stabilizing trends of interest rate and accessibility of Indian companies to foreign market for debt and equity, the ground situation has changed to a great extent.* ***As such, a fresh look is required to be given towards the approach for rate of return, that is, whether RoE approach vis-à-vis RoCE approach." (emphasis added)***

CERC, in its draft explanatory memorandum to CERC (Terms and Conditions of Tariff) Regulations 2009, has stated:

"3.4 The general sentiment of the members of the Central Advisory Committee was also in favour of continuing the existing RoE approach because of not-so-stable interest rate regime.

*3.5 In this context, **the Commission would like to reiterate that ROCE approach is definitely preferable over the RoE approach because of its inherent feature of inducing efficiency in fund management and encouraging competition**. However, the Commission cannot remain oblivious of the realities of the debt market, more so of the fluctuations in interest rates as witnessed in recent past. The Commission feels that unless the debt market stabilizes it may not be feasible to arrive at a normative interest rate which can be applied for calculating the return on capital employed. At the same time, the interest rates on loans advanced vary significantly from company to company depending upon its financial strength and standing in the market. It may not therefore be appropriate to assign the same normative interest rate – if at all such normative interest rate can be derived – for all companies across the board.*

3.7 The Commission is also aware of the fact that there still exists significant disparity in the nature of entities under the purview of the Commission. Implementation of ROCE approach would raise a large number of issues as it requires computation of annual Weighted Average Cost of Capital (WACC) due to progressive change and reduction in the capital employed. A single WACC for the entire power sector and the control period would not be appropriate as the terms and conditions at which a utility obtains loan and raises equity varies widely depending upon the credit rating of the utility and the time period. New investments, particularly by the private sector are generally targeted at a specified debt equity norm and the return on equity projected will give an appropriate signal of assured proper return on that investment.

3.8 Another important point worth noting in this context is that as per Section 61 of the Act, the State Commissions are also to be guided by the terms and conditions of tariff notified by CERC for generation and transmission. It would be all the more difficult for the State Commissions to adopt the normative interest rate, if any, notified by CERC for the utilities regulated by the State Commissions, since such utilities in some cases may not be in a position to bargain interest rate for loans equivalent to that availed by the large entities regulated by CERC.

3.9 Given these realities and with due regard to the sentiment of the stakeholders and the members of the Central Advisory Committee, the Commission has decided to continue with the existing RoE approach for the tariff period 2009-14."

CERC has noted in the draft Explanatory Memorandum that the ROCE approach is preferable over the RoE approach, as this approach induces efficiency in fund management and encourages competition. However, CERC has cited fluctuations in the debt market and difficulty in assigning the same normative interest rate for all the Companies across the board, as the reasons for continuing with the existing RoE approach. However, one way to accommodate fluctuations in interest rate is to take average of last four years when interest rates were high. As is evident, interest rates in FY 2009-10 have already started reducing. The concerns of CERC and Central Advisory Committee may be addressed by benchmarking cost of debt with Bank Rate, as discussed later in this Section. Hence, once the concerns are adequately addressed as discussed in detail later in this Section, ROCE approach may be preferable to ROE approach.

In Delhi, the principle for providing return to the transmission licensees and distribution licensees is based on the principle of Return on Capital Employed (RoCE) on a regulated rate base, with the weighted average cost of capital to be determined independently for each year of the Control Period. In case of generating companies, Return on Equity has been considered.

Relevant extracts of Consultative paper on MYT Regulations published by DERC are reproduced below:

"2.92 The National Tariff policy states that 'Balance needs to be maintained between the interests of the consumers and the need for investments at par with, if not in preference to other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector'.

2.93 In view of the above, many regulators for the process of MYT process are evaluating idea of implementing the concept of return on capital employed instead of normative ROE concept.

*2.94 **The ROCE concept gives incentives to the licensees to optimise the debt equity ratio. The approach recognises that the consumers should pay for the capital employed in the assets being used to serve the consumers, and ensure that the financing decisions of the distribution licensee do not affect consumer tariffs. It also makes it easier for the regulators as they do not have to monitor the debt and equity component separately and can concentrate on the overall performance of the licensees**."* emphasis added

Relevant extracts of MYT Regulations in Delhi are reproduced below:

"Return on Capital Employed

5.5 Return on Capital Employed (RoCE) shall be used to provide a return to the Distribution Licensee, and shall cover all financing costs, without providing separate allowances for interest on loans and interest on working capital.

......

5.8 The Regulated Rate Base for the ith year of the Control Period shall be computed in the following manner:

$RRBi = RRB\ i\text{-}1 + \Delta ABi/2 + \Delta WCi;$

Where,

'i' is the ith year of the Control Period, i = 1,2,3,4 for the first Control Period;

RRBi: Regulated Rate Base for the ith year of the Control Period;

ΔABi: Change in the Regulated Rate Base in the ith year of the Control Period. This component shall be the average of the value at the beginning and end of the year as the asset creation is spread across a year and is arrived at as follows:

$\Delta ABi = Invi - Di - CCi;$

Where,

Invi: Investments projected to be capitalised during the ith year of the Control Period and approved;

Di: Amount set aside or written off on account of Depreciation of fixed assets for the ith year of the Control Period;

CCi: Consumer Contributions pertaining to the ΔRRBi and capital grants/subsidies received during ith year of the Control Period for construction of service lines or creation of fixed assets;

RRB i-1: Regulated Rate Base for the Financial Year preceding the ith year of the Control period. For the first year of the Control Period, RRB i-1 shall be the Regulated Rate Base for the BaseYear i.e. RRBO;

RRBO = OCFAO – ADO – CCO;

Where;

OCFAO: Original Cost of Fixed Assets at the end of the Base Year available for use and necessary for the purpose of the Licenced business;

ADO: Amounts written off or set aside on account of depreciation of fixed assets pertaining to the regulated business at the end of the Base Year;

CCO: Total contributions pertaining to the OCFAo, made by the consumers towards the cost of construction of distribution/service lines by the Distribution Licensee and also includes the capital grants/subsidies received for this purpose;

ΔWCi: Change in normative working capital requirement in the ith year of the Control Period, from the (i-1)th year. For the first year of the Control Period (i=1), ΔWC1 shall be taken as the normative working capital requirement of the first year. Working capital for Wheeling of electricity shall consist of

i) Receivables for two months of Wheeling Charges; and

ii) Operation and maintenance expenses for one month.

5.9 Return on Capital Employed (RoCE) for the year 'i' shall be computed in the following manner:

*RoCE =WACCi * RRBi*

Where,

WACCi is the Weighted Average Cost of Capital for each year of the Control Period;

RRB - Regulated Rate Base is the asset base for each year of the Control Period based on the capital investment plan and working capital.

5.10 The WACC for each year of the Control Period shall be computed at the start of the Control period in the following manner:

$$WACC = \left[\frac{D/E}{1+D/E}\right] * r_d + \left[\frac{1}{1+D/E}\right] * r_e$$

Where,

D/E is the Debt to Equity Ratio and for the purpose of determination of tariff, debt-equity ratio as on the Date of Commercial Operation in case of new distribution line or substation or capacity expanded shall be 70:30. Where equity employed is in excess of 30%, the amount of equity for the purpose of tariff shall be limited to 30% and the balance amount shall be considered as notional loan. The interest rate on the amount of equity in excess of 30% treated as notional loan shall be the weighted average rate of the loans of the Licensee for the respective years and shall be further limited to the prescribed rate of return on equity in the Regulations. Where actual equity employed is less than 30%, the actual equity and debt shall be considered.

rd is the Cost of Debt and shall be determined at the beginning of the Control Period after considering Licensee's proposals, present cost of debt already contracted by the Licensee, and other relevant factors (risk free returns, risk premium, prime lending rate etc.);

re is the Return on Equity and shall be determined at the beginning of the Control Period after considering CERC norms, Licensee's proposals, previous years' D/E mix and other relevant factors. The cost of equity for the Wheeling Business shall be considered at 14% post tax.

In Andhra Pradesh, the RoCE approach has been adopted for Generation, Transmission and Distribution. Relevant extracts of MYT Regulations in Andhra Pradesh are reproduced as follows:

"2 Return on Capital Employed

2.1 Return on Capital Employed (RoCE) for the RRB for the year 'i' shall be computed in the following manner:

*RoCE = WACC * RRBi*

Where,

WACC is the Weighted Average Cost of Capital as fixed by the Commission for the Control period and expressed in terms of percentage;

RRB is the Regulated Rate Base (the asset base) approved by the Commission for each year of the Control period on which the Distribution Licensee shall be entitled to earn a return based on the Commission approved Weighted Average Cost of Capital (WACC).

i: ith year of the Control Period, i = 1, 2, 3 for the first Control Period

1. *The WACC shall be computed in the following manner:*

$$WACC = \left[\frac{D/E}{1+D/E}\right] * r_d + \left[\frac{1}{1+D/E}\right] * r_e$$

Where,

D/E is the Debt to Equity Ratio and shall be determined at the beginning of the Control Period after considering Distribution Licensee's proposal, previous years' D/E mix, market conditions and other relevant factors

rd is the Cost of Debt and shall be determined at the beginning of the Control Period after considering Distribution Licensee's proposals, present cost of debt, market conditions and other relevant factors.

re is the Return on Equity and shall be determined at the beginning of the Control Period after considering CERC norms, Distribution Licensee's proposals, previous years' D/E mix, risks associated with distribution & supply business, market conditions and other relevant factors

The Weighted Average Cost of Capital as determined above shall remain unchanged during the Control Period

2. *The Regulated Rate Base (RRB) for the purposes of computing the RoCE for a year of the Control Period will be computed in the following manner.*

$$RRBi = RRB\ i\text{-}1 + \Delta\ RABi + WCi$$

Where,

RRBi : Regulated Rate Base for the ith year of the Control period

ΔRABi: Change in the Rate Base in the ith year of the Control Period. This component would be the average of the value at the beginning and end of the year as the asset creation is spread across a year and is arrived at as follows:

$$\Delta RABi = (Invi - Di - CCi)/2$$

Where,

Invi: Investments projected to be capitalised during the ith year of the Control Period and approved.

Di: Amount set aside or written off on account of Depreciation of fixed assets for the ith year of the Control Period.

CCi: User Contributions pertaining to the ΔRABi and capital grants/subsidies received during ith year of the Control Period for construction of service lines or creation of fixed assets.

RRB i-1: Regulated Rate Base for the financial year preceding the ith year of the Control period and shall be determined on the basis of approved Capital Investment Plan referred to in clause 16.1 of this Regulation. For the first year of the Control Period, RRB i-1 will be the Regulated Rate Base for the Base Year i.e. RRBO. The values for the Base Year will be determined based on the latest audited accounts available, best estimates of the actuals pertaining to the relevant years and any other factors considered relevant by the Commission.

RRBO = OCFAO – ADO – CCO ,

where

OCFAO: Original Cost of Fixed Assets at the end of the Base Year available for use and necessary for the purpose of the licensed business

ADO: Amounts written off or set aside on account of depreciation and advance against depreciation if any, of fixed assets pertaining to the regulated business at the end of the Base Year

CCO: Total contributions pertaining to the OCFAo, made by the users towards the cost of construction of distribution/service lines by the Distribution Licensee and also includes the capital grants/subsidies received for this purpose.

WCi: Working Capital Requirement in the ith year of the Control Period and shall be considered as being equal to one twelfth of the Operations and Maintenance expenses as allowed for that year.

Thus, in case ROCE approach is to be adopted for allowing Returns to the investors, the following framework would be applicable:

3.1.3 Computation of ROCE

ROCE can be computed by applying the rate of return (weighted average cost of capital) on the capital employed, using the following formulae:

ROCE = WACC X RRB

where,

WACC is the Weighted Average Cost of Capital

RRB is the Regulated Rate Base

Rate of Return (WACC)

The rate of return that is required by the investors/financial markets to finance an asset is called the Cost of Capital. The Cost of Capital is usually computed as a weighted average of the cost of debt and equity. The weighted average cost of capital (WACC) can be computed using the following formula:

$WACC = [(1-g) * r_e] + [g * r_d]$

where,

g is the level of gearing or leverage in a Company, i.e., the proportion of debt in the total capital structure (i.e., debt + equity)

r_d is the cost of debt finance

r_e is the cost of equity finance

The cost of debt is generally estimated by considering the premium to the risk free rate at which, the Company is likely to raise debt from the debt market. Since debt is a contractual obligation between the Utility and its lenders, the cost of debt depends on the rate at which the funds are lent to the Company. The cost of equity is an estimate of rate of return for the Utility business comparable to returns earned on investments in enterprises with similar risk profile. It is the opportunity cost for investors against alternative investment opportunities.

Capital Employed (Regulated Rate Base)

Regulated Rate Base (RRB) is computed as actual original cost of fixed assets, less the accumulated depreciation, which is also known as Net Fixed Assets (NFA). The capital grants and subsidies should be deducted from the total fixed assets while calculating the total capital employed, as these funds are not capital employed by the Utility and hence, the Utility is not entitled to earn a return on the these funds. Consumer Contribution is also capital provided by the consumer, and hence, the Utility should not be entitled to any return on the same. Under the ROCE approach, the capital employed gradually reduces as NFA will get reduced on year to basis on account of accumulated depreciation, which will be offset to the extent of additional capitalisation, if any. It is also proposed that interest on working capital may be allowed separately on normative basis, instead of including it regulated rate base computation.

However, for implementing the RoCE approach, the following three critical issues need to be addressed, viz.,

A. What will be the benchmark interest rate for debt?

B. What will be the benchmark cost of equity?

C. What would be the normative Debt:Equity ratio for computing rate of return?

The possible solutions to each of the issues are discussed in subsequent paragraphs.

3.1.3.1 Benchmark interest rate for debt

The interest rates as per the secondary debt market are considered to be the ideal reference points for establishing the benchmark cost of debt. A similar approach is currently followed by the Regulator (Ofgem) in UK while determining the cost of capital, wherein, they have considered the best long-term estimate of the risk-free rate and applied a debt premium in the range of 1.0 to 1.5 per cent in addition to the risk-free rate.

In the Indian context, benchmarking with the Bank Rate notified by the Reserve Bank of India (RBI) may be a better option for arriving at the normative cost of debt. The Bank Rate is the interest rate charged by the Reserve Bank of India (RBI) on loans and advances to Banks to control money supply in the economy and the banking sector. A fluctuation in the Bank Rate triggers a ripple-effect as it impacts every sphere of the country's economy. It should be noted that the rate at which the banks and Financial Institutions lend to the

Utilities is higher than the Bank Rate. The difference between the Bank Rate and the lending rate to the Utilities is considered as the spread. It may also be noted that under the earlier framework governing the Schedule VI licensees, the Returns to the investors was also benchmarked with the prevailing Bank Rate, with a spread, which was varied from time to time to reflect the then prevailing financial market conditions.

To determine the spread between average interest rate and the Bank Rate for each Utility, the following methodology has been used:

Step-1: Compile the average interest rate for each Utility for the period from FY 2006-07 to FY 2009-10, based on approved values in their respective Tariff Orders.

Step-2: Compile Bank Rate for the period from FY 2006-07 to FY 2009-10, from Reserve Bank of India's website.

Step-3: Compute spread for each Utility for the period from FY 2006-07 to FY 2009-10 with respect to Bank Rate.

Step-4: Compute four-year average based on data on spread for each Utility to arrive at single spread value.

The average interest rate has been considered, since loan portfolios of Utilities comprise both existing and new loans. ABPS Infra has analysed the movement of average interest rates of various utilities in the State vis-à-vis Bank Rate, as shown in the Tables below:

Table 2: Interest rate comparison for FY 2006-07

Utility	FY 2006-07		
	Average Interest Rate approved by the Commission	**Bank Rate**	**Spread of Average Interest rate with respect to Bank Rate**
Distribution Licensees			
RInfra -D	9.42%	6.00%	3.42%
BEST	10.20%	6.00%	4.20%
TPC-D	9.78%	6.00%	3.78%
MSEDCL	8.45%	6.00%	2.45%
Transmission Licensees			
RInfra -T	9.87%	6.00%	3.87%
TPC-T	9.70%	6.00%	3.70%
MSETCL	9.97%	6.00%	3.97%
Generation Companies/Business			

Utility	FY 2006-07		
	Average Interest Rate approved by the Commission	Bank Rate	Spread of Average Interest rate with respect to Bank Rate
RInfra -G	9.44%	6.00%	3.44%
TPC-G	9.92%	6.00%	3.92%
MSPGCL	4.83%	6.00%	-1.17%
Average Spread for Utilities			**2.45% to 4.2%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and RBI website

Table 3: Interest rate comparison for FY 2007-08

Utility	FY 2007-08		
	Average Interest Rate approved by Commission	Bank Rate	Spread of Average Interest rate with respect to Bank Rate
Distribution Licensees			
RInfra -D	8.90%	6.00%	2.90%
BEST	10.43%	6.00%	4.43%
TPC-D	9.50%	6.00%	3.50%
MSEDCL	9.75%	6.00%	3.75%
Transmission Licensees			
RInfra -T	8.55%	6.00%	2.55%
TPC-T	9.30%	6.00%	3.30%
MSETCL	10.52%	6.00%	4.52%
Generation Companies/Business			
RInfra -G	4.67%	6.00%	-1.33%
TPC-G	9.79%	6.00%	3.79%
MSPGCL	8.53%	6.00%	2.53%
Average Spread for Utilities			**2.53% to 4.43%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and RBI website

Table 4: Interest rate comparison for FY 2008-09

Utility	FY 2008-09		
	Average Interest Rate approved by Commission	Bank Rate	Spread of Average Interest rate with respect to Bank Rate
Distribution Licensees			
RInfra -D	8.88%	6.00%	2.88%
BEST	10.23%	6.00%	4.23%
TPC-D	10.44%	6.00%	4.44%

	FY 2008-09		
Utility	**Average Interest Rate approved by Commission**	**Bank Rate**	**Spread of Average Interest rate with respect to Bank Rate**
MSEDCL	10.61%	6.00%	4.61%
Transmission Licensees			
RInfra -T	9.01%	6.00%	3.01%
TPC-T	10.24%	6.00%	4.24%
MSETCL	12.38%	6.00%	6.38%
Generation Companies/Business			
RInfra -G	8.11%	6.00%	2.11%
TPC-G	10.07%	6.00%	4.07%
MSPGCL	9.30%	6.00%	3.30%
Average Spread for Utilities			**2.11% to 6.38%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and RBI website

Table 5: Interest rate comparison for FY 2009-10

	FY 2009-10			4-Year Average		
Utility	**Average Interest Rate approved by Commission**	**Bank Rate**	**Spread of Average Interest rate with respect to Bank Rate**	**Average Interest Rate**	**Average Bank Rate**	**Spread of Average Interest rate with respect to Bank Rate**
Distribution Licensees						
RInfra -D	8.81%	6.00%	2.81%	9.00%	6.00%	3.00%
BEST	10.66%	6.00%	4.66%	10.38%	6.00%	4.38%
TPC-D	9.28%	6.00%	3.28%	9.75%	6.00%	3.75%
MSEDCL	NA	6.00%		9.60%	6.00%	3.60%
Transmission Licensees						
RInfra -T	9.00%	6.00%	3.00%	9.11%	6.00%	3.11%
TPC-T	9.03%	6.00%	3.03%	9.57%	6.00%	3.57%
MSETCL	12.69%	6.00%	6.69%	11.39%	6.00%	5.39%
Generation Companies/Business						
RInfra -G	8.15%	6.00%	2.15%	8.57%	6.00%	2.57%
TPC-G	9.44%	6.00%	3.44%	9.81%	6.00%	3.81%
MSPGCL	NA	6.00%		8.92%	6.00%	2.92%
Average Spread for Utilities			**2.15% to 6.69%**			**2.57% to 5.39%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and RBI website

In the prevailing market scenario, the Bank Rate is 6%, and the spread is in the range of 2.57 % to 5.39% above the Bank Rate. Hence, it is proposed to adopt a spread of 4% over Bank Rate as on 31st March of previous financial year. This translates to an effective cost of debt of 10%.

It is proposed to reset the interest rates considered for the second Control Period, after the end of the Control period, i.e., before the commencement of the third Control Period, based on the trend of spread witnessed during the second Control Period.

3.1.3.2 Benchmark cost of equity?

The Commission has adopted the RoE approach while formulating the MERC (Terms and Conditions of Tariff) Regulations, 2005. The MERC Tariff Regulations stipulates that the Generation Companies and Transmission Licensees shall be allowed a return at the rate of 14 per cent per annum, on the amount of approved equity capital. The Distribution Licensees are allowed a return at the rate of 16 per cent per annum, on the amount of approved equity capital, for both, the Wires Business and the Supply Business.

In this context, the Tariff Policy stipulates:

> ***"a) Return on Investment***
>
> *Balance needs to be maintained between the interests of consumers and the need for investments while laying down rate of return. Return should attract investments at par with, if not in preference to, other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector.*
>
> *The Central Commission would notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital which shall be followed by the SERCs also. The rate of return notified by CERC for transmission may be adopted by the State Electricity Regulatory Commissions (SERCs) for distribution with appropriate modification taking into view the*

higher risks involved. For uniform approach in this matter, it would be desirable to arrive at a consensus through the Forum of Regulators.

While allowing the total capital cost of the project, the Appropriate Commission would ensure that these are reasonable and to achieve this objective, requisite benchmarks on capital costs should be evolved by the Regulatory Commissions."

CERC, in its explanatory memorandum to CERC (Terms and Conditions of Tariff) Regulations 2009, has stated:

"8.1 The Commission had specified a post-tax ROE rate of 16% for the tariff period 2001-04 and 14% for the tariff period 2004-09.

8.2 Section 5.3(a) of the Tariff Policy stipulates that while laying down rate of return the Commission shall maintain balance between the interests of consumers and the need for investments. The Central Commission would notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital which shall be followed by the SERCs also. The rate of return notified by CERC for transmission may be adopted by the State Electricity Regulatory Commissions (SERCs) for distribution with appropriate modification taking into view the higher risks involved. The policy also stipulates that for the purposes of return on equity, any cash resources available to the company from its share premium account or from its internal resources that are used to fund the equity commitments of the project under consideration should be treated as equity subject to certain limitations in regard to debt-equity ratio.

8.3 The power sector in India, during last few years, has been able create a lot of enthusiasm amongst the investors and attract investment. In the last five years, there have been rapid developments in the equity market and debt market related to power sector in India. Various CPSUs and private entities working in power sector have entered into primary market to raise funds. The Initial Public Offers floated by NTPC, PGCIL and Reliance Power were oversubscribed by 13.16, 64.50 and 61.52 times respectively. The sector is at the take off stage at present and there is a need to ensure that the confidence evinced is sustained.

8.4 The rate of return on equity may be fixed by using any of the scientific model like dividend growth model, price/earning ratio, capital asset pricing model, risk premium model, etc or by linking to an appropriate benchmark with a mark up. As on date only few entities working in power sector in India have entered into primary market and that too very recently. To calculate rate of return by using a scientific model one needs sufficient volume of related data for calculation of beta value, expected rate of return, P/E ratio, etc. Except a few companies, such as NTPC, Reliance Energy, PGCIL, not many generating companies and transmission licensees like those in the State Sector are listed in the Stock Exchange. As elsewhere mentioned, the State Commissions are also required to be guided by the procedures and methodologies prescribed by the Central Commission. We do not have sufficient data in regard to the power sector, particularly scripts traded in the secondary market. As such, it shall not be appropriate to estimate the rate of return by using any of the scientific models. Moreover the debt market in India is not yet stable. This leads to difficulty in linking the rate of return to a benchmark with a mark up.

8.5 The recent Initial Public Offers floated by NTPC, PGCIL and Reliance Power shows that, even with the existing post-tax rate of return @ 14%, the IPOs were able to create sufficient enthusiasm amongst the investors. As such, the Commission has come to the conclusion that the post tax rate of ROE of 14% may continue."

Regulation 15 of CERC (Terms and Conditions of Tariff) Regulations, 2009 stipulates:

*"15. **Return on Equity**.*

(1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with regulation 12.

(2) Return on equity shall be computed on pre-tax basis at the base rate of 15.5% to be grossed up as per clause (3) of this regulation:

*Provided that in case of projects commissioned on or after 1st April, 2009, an additional return of 0.5% shall be allowed if such projects are completed within the timeline specified in **Appendix-II**:*

Provided further that the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever.

(3) The rate of return on equity shall be computed by grossing up the base rate with the normal tax rate for the year 2008-09 applicable to the concerned generating company or the transmission licensee, as the case may be:

Provided that return on equity with respect to the actual tax rate applicable to the generating company or the transmission licensee, as the case may be, in line with the provisions of the relevant Finance Acts of the respective year during the tariff period shall be trued up separately for each year of the tariff period along with the tariff petition filed for the next tariff period.

(4) Rate of return on equity shall be rounded off to three decimal points and be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where t is the applicable tax rate in accordance with clause (3) of this regulation.

Illustration.-

(i) In case of the generating company or the transmission licensee paying Minimum Alternate Tax (MAT) @ 11.33% including surcharge and cess:

Rate of return on equity = 15.50/ (1-0.1133) = 17.481%

(ii) In case of generating company or the transmission licensee paying normal corporate tax @ 33.99% including surcharge and cess:

Rate of return on equity = 15.50/ (1-0.3399) = 23.481%"

ABPS Infra is the opinion that the risk associated with regulated businesses like the electricity sector is much lower when compared to the risks associated with the stock market. Hence, return expectations should be commensurate with the risk associated with the business. Since CERC has notified the rate of return for equity as 15.5% for Generation Companies and Transmission Licensees, it is proposed to adopt the same in Maharashtra also. For the Distribution Wires business, the cost of equity of 15.5% may be adopted, since by nature, it is very similar to the Transmission Business, and the risks involved are similar. For the supply business, a premium of 2% may be given to compensate for the risks associated with the nature of business. Hence, the cost of equity for supply business may be pegged at 17.5%.

3.1.3.3 Normative Debt to Equity ratio

The Commission, in the MERC (Terms and Conditions of Tariff) Regulations, 2005 has specified normative debt-equity ratio of 70:30.

CERC in its Explanatory Memorandum to CERC (Terms and Conditions of Tariff) Regulations 2009, has stated:

> *"7.0 Debt/Equity Ratio*
>
> *7.1 Financing plan of the project plays a predominant role in the determination of tariff. The present regulations applicable during the period 2004-09 contain provisions in regard to debt-equity ratio of the existing projects, new projects and apportionment of additional capitalization. It has been felt that the regulations should be simplified.*
>
> *7.2 As per the Tariff Policy, issued by the Government of India, all the new power projects would be financed in the debt-equity ratio of 70:30. The investors are free to put equity more than 30% of the project cost, but the excess equity deployed over and above 30% would be treated as notional loan, which would be serviced at weighted average rate of interest of the project over a weighted average tenure. However, if equity deployed is less than 30%, the same will be considered for determination of tariff. Further in RoE approach, equity does not get reduced after the loan is repaid. So, investors get RoE along with depreciation amount after loan repayment. In such case equity, if more than 30% will have adverse impact on consumers. Moreover, most of the generation projects are being financed in the debt-equity ratio of 70:30.*
>
> *7.3 Considering these aspects, the Commission proposes a uniform capital structure with a debt-equity ratio of 70:30 for all the power projects i.e. whether it is initial project cost, additional capital expenditure or renovation & modernization case. However, if equity is declared less than 30% actual amount of equity would be considered for tariff determination.*
>
> *7.4 In case of existing projects, the Commission has already allowed a capital structure while approving tariff for the period of 2004-09. The Commission has also considered additional capital expenditure as per the current Regulations. The capital structure of such projects, as approved by the Commission as on 31.03.2009, shall not be disturbed in the next tariff period. However, additional capital expenditure, if any, shall be serviced in the debt-equity ratio of 70:30."*

Regulation 12 of CERC (Terms and Conditions of Tariff) Regulations, 2009 stipulates:

*"12. **Debt-Equity Ratio**. (1) For a project declared under commercial operation on or after 1.4.2009, if the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:*

Provided that where equity actually deployed is less than 30% of the capital cost, the actual equity shall be considered for determination of tariff:

Provided further that the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment."

For the purpose of computing the ROCE under the MYT framework, the normative debt-equity ratio of 70:30 has been considered, since this ratio has been standardized for the power sector across the country.

ROCE computation for Generation business

Particulars	Debt	Equity
Cost of Capital	10%	15.5%
Debt-equity Mix	70%	30%
ROCE	**11.65%**	

ROCE computation for Transmission & Distribution Wires business

Particulars	Debt	Equity
Cost of Capital	10%	15.5%
Debt-equity Mix	70%	30%
ROCE	**11.65%**	

ROCE computation for Retail Supply business

Particulars	Debt	Equity
Cost of Capital	10%	17.5%
Debt-equity Mix	70%	30%
ROCE	**12.25%**	

Source: ABPS Infra Analysis

The ROCE allowable during the second Control Period has been computed considering normative cost of debt, normative cost of equity and normative debt-equity ratio as discussed earlier in this Section, which works out to 11.65% for Generating Companies, Transmission Licensees, and Distribution Wires Licensee/Business, and 12.25% for Retail Supply Licensee/Business.

3.1.4 Post-Tax Vs Pre-Tax Rate of Return

Under the MERC Tariff Regulations, the Commission has been allowing post-tax rate of return and has allowed income-tax as a pass through, to be recovered based on actual income tax paid by the Utilities. The issue is whether the returns to the investor should be allowed on a post-tax basis or on pre-tax basis. Both the approaches have merits and demerits.

Under the post-tax approach, the Commission has to assess the income tax liability at the time of determination of ARR and tariff, which can be complicated in case of entities that are undertaking other non-core businesses also, which are not regulated. This problem exists in Maharashtra for Utilities like TPC and RInfra, which have different businesses that are regulated by the Commission (generation, transmission and distribution), as well as several other businesses in the power sector in other States (Delhi, Karnataka, Andhra Pradesh, Kerala,etc.) as well as other unregulated businesses in Maharashtra as well as other States (EPC Business, etc.) Another negative aspect of the existing post-tax approach is that there is no inducement for better tax planning. However, in case of post tax returns, the tax benefits available to the sector are passed on to the consumers. Since, in Maharashtra, the Utilities are engaged in such other businesses and hence, the assessment of income tax liability is complicated on a post tax basis.

On the other hand, the pre-tax return approach, is aimed at encouraging power sector entities to do better tax planning and also does not have the above de-merits of post-tax return approach. The income tax liability does not have to be projected in advance, and at the end of the year, does not have to be matched with the actual income tax paid, etc. The issue of estimating the income tax for Utilities operating in several States/Businesses will also not arise.

CERC, in its Explanatory Memorandum to CERC (Terms and Conditions of Tariff) Regulations, 2009, has stated:

> *"9.1 The Commission specified, for the tariff period 2001-04 and 2004-09 post-tax rate of return on equity and allowed income tax, in respect of income from core businesses only, as pass-through to be recovered separately on actual. In general, the profit of the utilities should be equal to RoE specified because all other elements of tariff are based on the general premise of pass-through. But practically, the profit of the utilities is influenced by other factors such as profits of non-core business carried out by the utilities, UI earnings,*

efficiency gains, incentive earned, difference in the depreciation allowed under tariff and the Income Tax Act, 1961, income tax holiday allowed in power sector etc.

9.2 The issue posed in the approach paper was whether the existing system of post-tax return should be continued or pre-tax return, factoring the tax rates be allowed. The Commission discussed various options like post-tax rate of return, as existing, post-tax rate of return with a cap limiting tax burden to the RoE component only, normative Income Tax on admitted RoE subject to tax actually paid and pre-tax rate of return. Most of the utilities are enjoying income tax holiday and/or paying Minimum Alternate Tax. Under pre-tax return, it may not be possible to pass on these benefits to the beneficiaries. There is also the uncertainty in regard to applicable income tax rate, as the tax rates and other concessions keep changing from year to year.

9.3 Moving to a normative pre-tax regime shall require grossing up by the present post tax RoE by the prevalent tax rates to determine the appropriate Pre-tax Return on Equity. Any change in tax rates and other concessions which are not within the control of generating company or the transmission licensee need to be fully adjusted while determining an appropriate rate. There are not many avenues for tax planning in the power business except for section 80 IA under the Income Tax Act. The tax holiday is for limited period and not for entire life of the project.

While new projects would be entitled to come under MAT on account of tax holiday, older plants may have to pay tax at normal rates which is about three times higher than the MAT. In view of the difference in rates of tax, it may not be possible to arrive at single rate of pre-tax return and it may not be advisable to arrive at different pre-tax rates for different entities based on their applicable & effective tax rates. Changing from post tax to pre tax would expose the investors to tax risk which is beyond the control of the entity.

9.4 Considering the above facts the Commission proposes to continue with the existing system of post tax return with certain modifications to insulate the beneficiaries, to the extent possible, from the burden of paying tax on income beyond the allowable RoE by excluding income on incentive and net UI income.

9.5 This will ensure that the benefit of income tax exemptions available for infrastructure projects, etc is passed on to the beneficiaries and at the same time the beneficiaries do not have to pay income tax on income components like income on incentive and net UI income.

(2) Return on equity shall be computed on pre-tax basis at the base rate of 15.5% to be grossed up as per clause (3) of this regulation:

Provided that in case of projects commissioned on or after 1st April, 2009, an additional return of 0.5% shall be allowed if such projects are completed within the timeline specified in ***Appendix-II****:*

Provided further that the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever.

(3) The rate of return on equity shall be computed by grossing up the base rate with the normal tax rate for the year 2008-09 applicable to the concerned generating company or the transmission licensee, as the case may be:

Provided that return on equity with respect to the actual tax rate applicable to the generating company or the transmission licensee, as the case may be, in line with the provisions of the relevant Finance Acts of the respective year during the tariff period shall be trued up separately for each year of the tariff period along with the tariff petition filed for the next tariff period.

(4) Rate of return on equity shall be rounded off to three decimal points and be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where t is the applicable tax rate in accordance with clause (3) of this regulation.

Illustration.-

(i) In case of the generating company or the transmission licensee paying Minimum Alternate Tax (MAT) @ 11.33% including surcharge and cess:

Rate of return on equity = 15.50/ (1-0.1133) = 17.481%

(ii) In case of generating company or the transmission licensee paying normal corporate tax @ 33.99% including surcharge and cess:

Rate of return on equity = 15.50/ (1-0.3399) = 23.481%"

ABPS Infra is of the opinion that income tax is chargeable on the profit earned by the Company. In every other business, the income taxes are paid from out of the profits

earned from the business, and such payment of income tax is not allowed to be charged as an expense under the Income Tax Act, while computing the taxable profit. In the stock market too, while the risks as well as the returns are higher, income tax has to be paid on the profits earned through purchase and sale of shares. Hence, in ABPS Infra's view, it is not appropriate for the income tax to be passed through to the consumers as an expense incurred by the Utility. The income tax needs to be absorbed by the Utility itself.

Hence, pre-tax ROCE of 11.65% is proposed to be allowed during the second Control Period for Generating Companies, Transmission Licensees/Businesses, and Distribution Wire Licensees/Businesses, and pre-tax ROCE of 12.25% is proposed to be allowed during the second Control Period for Retail Supply Licensees/Businesses.

3.1.5 Proposed Mechanism for Implementing Return on Capital Employed

Return on Capital Employed (RoCE) is proposed to be used to provide return to the Utilities, and shall cover all financing costs except the interest on working capital, and no separate expenditure on account of interest on loans will be considered.

The Regulated Rate Base (RRB) shall be equal to the total capital employed, i.e., the original cost of assets less the accumulated depreciation. Capital Work In Progress (CWIP), Consumer Contribution, and Capital Subsidies/Grants shall not form part of the RRB.

In Maharashtra, for the second Control Period, the MYT Petition of the Utilities shall consist of:

a. Truing up requirement for FY 2008-09 based on Audited Accounts.

b. Provisional truing up requirement for FY 2009-10 based on six months actuals and revised estimates for the second half of FY 2009-10.

c. MYT Petition for the second Control Period, viz., FY 2010-11 to FY 2014-15

Hence, for the purpose of computation of RRB, it is proposed to consider the approved rate base for FY 2009-10 based on provisional truing up of FY 2009-10.

The RRB shall be determined for each year of the Control Period at the beginning of the Control Period based on the approved capital investment plan with corresponding capitalisation schedule. The Regulated Rate Base for the i^{th} year of the Control Period shall be computed in the following manner:

$RRB_i = RRB_{i-1} + AB_i / 2$;

Where,

'i' is the i^{th} year of the Control Period, i = 1,2,3,4, and 5 for the second Control Period;

RRB_i: Regulated Rate Base for the i^{th} year of the second Control Period;

AB_i: Change in the Regulated Rate Base in the i^{th} year of the Control Period. This component shall be the average of the value at the beginning and end of the year as the asset creation is spread across a year and shall be computed as follows:

$AB_i = Inv_i – D_i – CC_i$;

Where,

Inv_i: Investments projected to be capitalised during the i^{th} year of the Control Period and approved;

D_i: Amount set aside or written off on account of Depreciation of fixed assets for the i^{th} year of the Control Period;

CC_i: Consumer Contributions pertaining to the RRBi and capital grants/subsidies received during i^{th} year of the Control Period for construction of service lines or creation of fixed assets;

RRB_{i-1}: Regulated Rate Base for the Financial Year preceding the i^{th} year of the Control period. For the first year of the Control Period, RRB_{i-1} shall be the Regulated Rate Base for the Base Year i.e. RRB_O;

$RRB_O = OCFA_O – AD_O – CC_O$;

Where;

$OCFA_O$: Original Cost of Fixed Assets at the end of the Base Year available for use and necessary for the purpose of the regulated business;

AD_O: Amounts written off or set aside on account of depreciation of fixed assets pertaining to the regulated business at the end of the Base Year;

CC_O: Total contributions pertaining to the $OCFA_O$, made by the consumers towards the cost of construction of distribution/service lines by the Distribution Licensee and also includes the capital grants/subsidies received for this purpose;

Return on Capital Employed (RoCE) for the year 'i' shall be computed in the following manner:

$ROCE_i = WACC_i \times RRB_i$

Where,

$WACC_i$ is the Weighted Average Cost of Capital for each year of the Control Period as specified by the Commission and for the second Control Period it is proposed to be specified as 11.65% for Generating Companies, Transmission Licensees/Businesses, and Distribution Wire Licensees/Businesses, and 12.25% is proposed to be allowed during the second Control Period for Retail Supply Licensees/Businesses and;

RRB_i - Regulated Rate Base is the asset base for each year of the Control Period based on the capital investment plan approved by the Commission.

Regulated Rate Base primarily depends upon the Capital Expenditure Plan approved by the Commission. In any case, the Utilities have to submit the investment plan for the Commission's approval along with the MYT Petition for the second Control Period and it will be appropriate to stipulate the Regulated Rate Base for the Control Period considering all these aspects. Therefore, the MERC MYT Regulations should only stipulate the variables, which will be used to compute ROCE, and the methodology and approach to be followed in stipulating ROCE. **Accordingly, it is proposed that the Regulated Rate Base for the Utilities should be specified in the Order on MYT Petitions of respective Utilities.**

As per the provisions of prevailing MERC Tariff Regulations, Return on Equity is allowed on opening balance of equity invested in the Gross Fixed Assets for the generation business. However, for transmission, distribution wires and retail supply business, Return on Equity is allowed on opening balance of equity invested in the Gross Fixed Assets and 50 per cent of the equity component of the capitalised portion of the allowable capital cost, for such financial year. As it is cumbersome to compute the additional RoE for each scheme/project separately by considering the actual date of capitalisation, the additional RoE is given on 50% of equity component of the capitalised portion of the allowable capital cost.

It is proposed to continue the same approach while allowing ROCE as follows:

a. Generation business: Return on Capital Employed shall be allowed on opening balance of Regulated Rate Base at the beginning of the year.

b. Transmission, Distribution Wires and Retail Supply business: Return on Capital Employed shall be allowed on opening balance of Regulated Rate Base and 50 per cent of change of Regulated Rate Base for such financial year.

3.2 Capital Cost

The Forum of Regulators (FOR), in its Report on MYT for Distribution Licensees, has recommended as under:

> *"6.1.3 The distribution licensee should submit the business plan and power purchase plan for approval of the Commission, at least six months prior to submission of the MYT petition."*

The MERC Tariff Regulations stipulates:

> *"45.1 The Transmission Licensee shall submit an investment plan with full details of his proposed capital expenditure projects to the Commission for approval either along with the application for determination of tariff or separately, at such time as may be directed by the Commission:*
>
> *Provided that the investment plan shall be an annual rolling plan and the period covered by the plan shall coincide with the period for which forecasts/ estimates are being submitted as part of such application."*

> *"71.1 The Distribution Licensee shall submit an investment plan with full details of his proposed capital expenditure projects to the Commission for approval, either along with*

the application for determination of tariff or separately, at such time as may be directed by the Commission:

Provided that the investment plan shall be an annual rolling plan and the period covered by the plan shall coincide with the period for which forecasts/ estimates are being submitted as part of such application."

The above Regulations clearly bring out the need to file separate investment plan for approval of capital expenditure. This is critical, since the capital expenditure has a significant bearing on the tariff payable by the consumers, on account of the pass through of the related expenses like depreciation, advance against depreciation, interest on long-term loans, and return on equity etc., under the existing MERC Tariff Regulations. For new generating stations, the Commission has to approve the tariff after the Commercial Operation Date (COD) of the Project, and while doing so, the Commission will have to scrutinise the completed Project cost. The provisions related to prior approval of capital expenditure for transmission and distribution system needs to be retained, as proposed in the earlier Section.

The investment plan for approval of capital expenditure needs to be submitted along with the MYT Petition, if not prior to the submission of the MYT Petition, since the Commission will require adequate time to analyse the scheme, projected cost and reasonableness of the same, financing plan, interest during construction, use of efficient technology, benefits projected, cost-benefit analysis, need for the capital expenditure to meet projected load growth, Supply Code provisions, obligations under Standards of Performance, etc.

Variation between approved and actual values of capital expenditure and capitalisation significantly influences computation of tariff. Further, as regards capital expenditure, the Commission has instituted a process of giving in-principle approval for the capital expenditure schemes costing above Rs. 10 Crore (together known as DPR Schemes), wherein the Utility has to submit Detailed Project Report (DPR) as well as the expected cost-benefit analysis, pay back period, etc., as per well laid out guidelines. Schemes costing less than Rs. 10 Crore are considered as non-DPR schemes and the Utilities are not required to submit any DPR for the approval of the same.

Also, the quantum of capital expenditure under non-DPR schemes should not be very high, as compared to the DPR schemes, as this defeats the very purpose of classifying schemes costing above Rs. 10 Crore as DPR schemes and requiring regulatory scrutiny of the schemes.

In view of the above, as a general rule, in the latest APR Orders, the Commission has stipulated that the total capital expenditure and capitalisation on non-DPR schemes in any year should not exceed 20% of that for DPR schemes during that year. To achieve the purpose, the purported non-DPR schemes should be packaged into larger schemes by combining similar or related non-DPR schemes together and converted to DPR schemes, so that the in-principle approval of the Commission can be sought in accordance with the guidelines specified by the Commission.

Further, the investment on capex schemes is an ongoing process for any Utility/Licensee. The scope, objective and benefits are identified while formulating project reports. After implementation of the scheme, before capitalisation, the benefits are to be demonstrated by the Utility. The Utility is required to execute the capex schemes in a phased manner so as to minimise tariff shock attributable to capex implementation.

To understand the significance of the capitalisation claimed by Utilities, the closing GFA over the last four to five years have been compiled as under:

Table 6: Comparison of Closing GFA* of Utilities

Utility	FY 2004-05	FY 2005-06	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	Increase over last 5 years
	Actuals	**Actuals**	**Actuals**	**Utility Submission**	**Revised Estimates**	**Projected**	
BEST	**1023**	**1085**	**1157**	**1309**	**1435**	**1572**	**54%**
RInfra-G	1295	1303	1311	1560	1592	1655	**28%**
RInfra-T	285	292	298	304	406	943	**231%**
RInfra-D	1708	1934	2347	2594	2956	3480	**104%**
Total RInfra	**3287**	**3528**	**3957**	**4458**	**4954**	**6078**	**85%**

Utility	FY 2004-05	FY 2005-06	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	Increase over last 5 years
	Actuals	Actuals	Actuals	Utility Submission	Revised Estimates	Projected	
TPC-G	2595	2678	2714	2739	3086	3307	**27%**
TPC-T	966	973	1046	1089	1262	1607	**66%**
TPC-D	282	289	395	436	523	847	**200%**
Total TPC	**3844**	**3941**	**4155**	**4263**	**4872**	**5761**	**50%**
MSPGCL	9437	9642	9985	10121	10382	11219	**19%**
MSETCL	8322	8633	8965	9831	11016	13896	**67%**
MSEDCL	8894	9428	10371	11807	14445	19911	**124%**
Total MSEB	**26653**	**27703**	**29320**	**31759**	**35843**	**45026**	**69%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available.

It is clear from the above Table that the Gross Fixed Assets have increased in the range 19-28%, 66-231%, and 54-200% for the Generation, Transmission, and Distribution Business, respectively, over the last five years. The pace of asset addition has increased by leaps and bounds over the last five years. The addition to the asset base is clearly not commensurate either with the increase in sales or increase in demand in MW served. Since, the Utilities were able to serve the existing consumer base well enough with the existing assets, the rationale for this steep increase in the asset base needs to be examined further.

In the regulated business, the returns to the investors are linked to the equity invested in the business, which in turn is directly linked to the existing asset base and assets added every year. The steep increase in the asset base every year has resulted in increasing the returns from the regulated business. For the purpose of APR exercise for FY 2008-09 and revised projection for FY 2009-10 for Utilities, the Commission has substantially reduced the capitalisation as compared to the projected capitalisation by the Utilities, which is shown in table below.

Table 7: Comparison of Capitalisation of sought by Utilities and Approved by the Commission

Utility		FY 2007-08	FY 2008-09	FY 2009-10
BEST	Petition	156	129	140

Utility		FY 2007-08	FY 2008-09	FY 2009-10
	Approved	91	69	70
	Percentage Capitalisation Approved	59%	53%	50%
RInfra				
RInfra-G	Petition	249	38	63
RInfra-T		6	102	537
RInfra-D		285	376	538
Total RInfra		540	516	1138
RInfra-G	Approved	236	23	4
RInfra-T		6	47	29
RInfra-D		121	193	196
Total RInfra		363	263	229
RInfra-G	Percentage Capitalisation Approved	95%	60%	6%
RInfra-T		100%	46%	5%
RInfra-D		42%	51%	36%
Total RInfra		67%	51%	20%
TPC				
TPC-G	Petition	54	350	220
TPC-T		51	175	345
TPC-D		42	87	324
Total TPC		148	612	889
TPC-G	Approved	25	85	87
TPC-T		51	74	118
TPC-D		42	47	11
Total TPC		118	205	216
TPC-G	Percentage Capitalisation Approved	46%	24%	40%
TPC-T		100%	42%	34%
TPC-D		100%	53%	3%
Total TPC		80%	34%	24%
MSEB				
MSPGCL	Petition	110	249	780
MSETCL		867	1185	2879
MSEDCL		1108	2860	5821
Total MSEB		2085	4293	9481
MSPGCL	Approved	110	125	127
MSETCL		245	491	618

Utility		FY 2007-08	FY 2008-09	FY 2009-10
MSEDCL		463	942	1298
Total MSEB		819	1558	2042
MSPGCL	Percentage Capitalisation Approved	100%	50%	16%
MSETCL		28%	41%	21%
MSEDCL		42%	33%	22%
Total MSEB		39%	36%	22%

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and ABPS Infra analysis.

It is clear from the above Table that the capitalisation approved by the Commission is in the range 3-60% for FY 2008-09 and FY 2009-10. The impact of capex related expenses (depreciation, interest, and Return on Equity) on tariff of Distribution Utilities has been compiled as under:

Table 8: Impact of Capex related expenses on Distribution Utilities (in Rs/kWh)

	FY 2007-08		FY 2008-09		FY 2009-10	
	Petition	**Approved**	**Petition**	**Approved**	**Petition**	**Approved**
MSEDCL	0.22	0.20	0.25	0.21	0.34	0.20
RInfra-D	0.40	0.37	0.43	0.37	0.48	0.37
TPC-D	0.18	0.17	0.22	0.20	0.38	0.26
BEST	0.38	0.37	0.44	0.39	0.48	0.39

Source: ABPS Infra analysis

Table 9 : Capex related expenses of Distribution Utilities as percentage of Average Cost of Supply (%))

	FY 2007-08		FY 2008-09		FY 2009-10	
	Petition	**Approved**	**Petition**	**Approved**	**Petition**	**Approved**
MSEDCL	5.9%	5.5%	5.9%	5.2%	7.6%	5.0%
RInfra-D	7.1%	6.9%	5.7%	5.1%	6.9%	5.8%
TPC-D	3.0%	3.1%	4.0%	3.7%	7.2%	6.7%
BEST	5.8%	5.8%	5.4%	4.9%	6.4%	8.1%

Source: ABPS Infra analysis

As seen from the above Tables, capex related expenses account for 3 to 8% of the average cost of supply, which is substantially high. In order to limit the impact of Capex related expenses on the total Revenue Requirement of the Utility, a cap on capex related expenses is proposed, say, capex related expenses should not be more than 5%of ACoS of that financial year. This cap in absolute terms should not be more than 20-25 paise /unit.

Since capital expenditure has a tremendous bearing on several expenditure elements, some additional issues to be addressed under this aspect include:

a) Whether the actual capital cost should be considered or the approved capital cost, subject to prudence check, is to be considered?
b) Expenditure on Renovation & Modernisation and life extension of Plant
c) Expenditure involving replacement of asset/works arising out of contingency/accident, e.g., Floods, fire, etc.

The Commission's views on the above issues have been elaborated below:

a) It is proposed that the actual capital expenditure should not be considered for determining the capital cost. Rather, the approved capital cost should be considered for all tariff determination purposes, and if there is sufficient justification provided for any escalation in the project cost, then the same should be approved. On the other hand, in case of a situation where in the actual completed capital cost is lower than the approved capital cost, then the actual capital cost will have to be considered. However, since capital expenditure is a controllable parameter, the Utility may be entitled to some incentive on account of the reduction in capital expenditure, and the incentive could be given in the form of a specified proportion of the savings on account of the reduction in capital cost, over the life of the project.

b) Expenditure on Renovation & Modernisation and life extension of Plant should be added to the capital cost, upon approval by the Commission, since such expenses result in improvement in operational efficiency of the generation Stations and other equipment. At the same time, the benefits of R&M or life extension programme in terms of improvement of performance parameters and reduction in operational costs also needs to be passed on to consumers.

c) There should be a provision for revising the Capital Cost for inclusion of the expenditure involving replacement of assets arising out of contingency/accident, e.g., Floods, fire, etc., and for expenditure arising out of statutory provisions/change of law.

d) Further, depreciation has to be computed on the basis of net addition to the asset base, since in some cases, the assets are upgraded.

The Forum of Regulators (FOR), in its Report on MYT, has recommended that:

> *"6.1.18 A consultancy study should be undertaken for evolving the norms for capital expenditure by distribution licensees. Databases developed through RIMS can form the basis for prudence check for capex proposals. For realistic assessment of capex requirements, standard guidelines should be developed and rules set for prioritisation of schemes."*

Hence, there is a need to link the capital expenditure being incurred by the Utility and the trajectory of improvement in performance parameters, as proposed in the capital expenditure scheme submitted for the Commission's approval. The Utility has to be made accountable for ensuring that the stated benefits of the capital expenditure, wherever measurable, are realised and are passed on to the consumers in terms of improved operational efficiency and reduced tariffs. However, this linkage would be possible only in cases were there is a direct linkage between capital expenditure approved and performance norms, viz., reduction of distribution losses, improvement in quality of supply, etc. Hence, while approving the capital expenditure, the Commission will have to identify aspects where direct linkage is possible, for which scheme-wise accounting of capital expenditure and capitalisation is essential. Further, in case the projected performance norms are not achieved, even after incurring the approved capital expenditure, then it is proposed that the corresponding capital expenditure related expense heads, viz., depreciation and Return on Capital Employed (ROCE) will be disallowed/reduced once the Control Period is over. The disallowance of the impact of the capital expenditure related heads in the subsequent Control Period may be done with or without considering the carrying cost on the same, depending on the justification submitted by the Utility for the non-achievement of the performance norms despite incurring the capital expenditure.

3.3 Depreciation

The principles behind the charging of depreciation and the depreciation rates have been a subject of debate over the years, including the linkage of depreciation to creation of a reserve fund for replacement of assets versus the linkage of depreciation to providing cash flow for repayment of loans taken by the Utility.

In this context, Clause 5 (c) of the Tariff Policy stipulates:

> *"**The Central Commission may notify the rates of depreciation in respect of generation and transmission assets**. The depreciation rates so notified would also be applicable for distribution with appropriate modification as may be evolved by the Forum of Regulators.*
>
> ***The rates of depreciation so notified would be applicable for the purpose of tariffs as well as accounting.***
>
> ***There should be no need for any advance against depreciation.***
>
> *Benefit of reduced tariff after the assets have been fully depreciated should remain available to the consumers. "emphasis added*

For Generation Companies, Regulation 34.4 of the MERC (Terms & Conditions of Tariff) Regulations, 2005 stipulates:

> *"34.4 Depreciation, including Advance Against Depreciation*
>
> *34.4.1 Depreciation*
>
> *For the purpose of tariff, depreciation shall be computed in the following manner, namely:*
>
> *(i) The value base for the purpose of depreciation shall be the original cost of the asset as approved by the Commission in accordance with Regulation 30;*
>
> *(ii) Depreciation shall be calculated annually, based on straight line method at the rates provided in the **Annexure - I** to the Regulation:*
>
> *Provided that the residual life of the asset shall be considered as 10 per cent and depreciation shall be allowed up to maximum of 90 per cent of the original cost of the asset:*
>
> *Provided further that land is not a depreciable asset and its cost shall be excluded from the original cost for the purpose of calculation of depreciation:*

Provided also that the provisions of the Statements of Accounting Standards (AS6):

Depreciation Accounting of the Institute of Chartered Accountants of India shall apply to the extent not inconsistent with these Regulations.

34.4.2 Advance Against Depreciation

In addition to depreciation, the Generating Company shall be entitled to Advance Against Depreciation, calculated in the manner given in Regulation 32.3 above.

34.4.3 The Generating Company shall be permitted to recover amortisation of intangible assets upto such level as may be approved by the Commission.

Explanation – for the purpose of this Regulation, the term "intangible assets" shall mean such pre-operative and promotional expenditure incurred in cash and shown as a debit in the capital account of the Generating Company as has fairly arisen in promoting the Generation Business and shall exclude any amount paid or otherwise accounted as goodwill."

For Transmission Licensees, Regulation 50.4 of the MERC (Terms & Conditions of Tariff) Regulations, 2005 stipulates:

"50.4 Depreciation, including Advance Against Depreciation

50.4.1 The Transmission Licensee shall be permitted to recover depreciation on the value of fixed assets used in the Transmission Business computed in the following manner:

(a) The approved original cost of the project/ fixed assets shall be the value base for calculation of depreciation;

*(b) Depreciation shall be computed annually based on the straight line method at the rates specified in the **Annexure I** to these Regulations:*

Provided that the residual value of the asset shall be considered at 10 per cent of the allowable capital cost and depreciation shall be allowed upto a maximum of 90 per cent of the allowable capital cost of the asset:

Provided further that depreciation shall not be permitted on land and the value of land shall be excluded from the allowable capital cost for the purpose of calculation of depreciation:

Provided also that the provisions of the Statements of Accounting Standard (AS 6):

Depreciation Accounting shall apply, to the extent not inconsistent with these Regulations, in calculating depreciation under these Regulations.

50.4.2 In addition to depreciation, the Transmission Licensee shall be entitled to Advance Against Depreciation, computed in accordance with Regulation 48.3 above.

50.4.3 The Transmission Licensee shall be permitted to recover amortisation of intangible assets upto such level as may be approved by the Commission.

Explanation – for the purpose of this Regulation, the term "intangible assets" shall mean such pre-operative and promotional expenditure incurred in cash and shown as a debit in the capital account of the Transmission Licensee as has fairly arisen in promoting the Transmission Business and shall exclude any amount paid or otherwise accounted as goodwill."

Similar provisions exist for Distribution Wire Business and Retail Supply Business also.

The MERC (Terms and Conditions of Tariff) Regulations, 2005, has stipulated the straight line method for determination of Depreciation expenses for the Generation, Transmission, Distribution Wire, and Retail Supply business, and a residual value of 10%, and provides for Advance against Depreciation (AAD) in case the cumulative loan repayment exceeds the cumulative depreciation.

The existing MERC Tariff Regulations provide for recovery of amortisation of intangible assets up to such level as may be approved by the Commission. However, such a provision does not exist under the CERC Tariff Regulations. Hence, it is proposed to discontinue the recovery of amortisation of intangible assets under depreciation expenses.

Further, in the context of Advance against Depreciation, Clause 5 (c) of the Tariff Policy stipulates:

"The Central Commission may notify the rates of depreciation in respect of generation and transmission assets. The depreciation rates so notified would also be applicable for distribution with appropriate modification as may be evolved by the Forum of Regulators.

The rates of depreciation so notified would be applicable for the purpose of tariffs as well as accounting.

There should be no need for any advance against depreciation.

*Benefit of reduced tariff after the assets have been fully depreciated should remain available to the consumers. "(**emphasis added**)*

The CERC (Terms and Conditions of Tariff) Regulations, 2009, stipulates:

"17. Depreciation (1) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission.

(2) The salvage value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the capital cost of the asset.

Provided that in case of hydro generating stations, the salvage value shall be as provided in the agreement signed by the developers with the State Government for creation of the site:

Provided further that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciable value shall correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff.

(3) Land other than the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the asset.

*(4) Depreciation shall be calculated annually based on Straight Line Method and at rates specified in **Appendix-III** to these regulations for the assets of the generating station and transmission system:*

Provided that, the remaining depreciable value as on 31st March of the year closing after a period of 12 years from date of commercial operation shall be spread over the balance useful life of the assets.

(5) In case of the existing projects, the balance depreciable value as on 1.4.2009 shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto 31.3.2009 from the gross depreciable value of the assets.

(6) Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on pro rata basis.

The Tariff Policy stipulates that the depreciation rates specified by the CERC should be adopted for generation and transmission business, and may be adopted for the distribution business also, after suitable modification to be undertaken by the Forum of Regulators. The Tariff Policy also states that the same rate of depreciation should be considered for tariff purposes as well as accounting purposes and that there should be no need of providing Advance Against Depreciation (AAD) while determining the tariff. CERC Tariff Regulations have also removed the provision of AAD. Hence, it is proposed to discontinue the allowance of AAD.

Depreciation can be computed using one of the following options:

- Straight Line Method linked to useful life of the asset
- Depreciation as per Companies Act

Either the depreciation rates specified under the Companies Act or the Straight Line Method of depreciation linked to useful life of the asset could be adopted. Adopting the first option will meet the objectives of the Tariff Policy, as the same depreciation rate will be applicable for both tariff and accounting purposes. However, this approach may result in front-loading the expenses and hence, tariff to a certain extent.

The Straight Line Method linked to useful life of the asset has been in vogue for some time now, and has the merit of ensuring that the expenses and tariff charged to the consumers are not higher in the initial years.

As regards the issue of whether normative life of asset should be considered for computing depreciation, it is proposed to adopt the CERC specified life of asset, philosophy of linking depreciation with repayment of loan, and depreciation rates as provided in the Appendix-III of CERC Tariff Regulations, 2009.

It needs to be emphasized that scheme-wise tracking of capital expenditure, capitalisation, financing pattern, repayment obligations and depreciation expenses, needs to be done, for generation, transmission, distribution wire, and retail supply business. Also, depreciation may be charged from the first year of commercial operation. It is proposed to charge depreciation only on the opening Gross Fixed Assets at the beginning of the year, since it may not be feasible for the Commission to validate the exact date of capitalisation of the asset, in case of operation of the asset for part of the year.

3.4 Interest on Working Capital (IWC)

In this context, Clause 8.2.1 (4) of the Tariff Policy stipulates:

> *"Working capital should be allowed duly recognising the transition issues faced by the utilities such as progressive improvement in recovery of bills."*

The MERC ((Terms & Conditions of Tariff) Regulations, 2005 provides for allowing normative interest on working capital and stipulates,

i) Working Capital (Generation Business)

"34.5 Interest on Working Capital

(a) In case of Coal based/ oil-based/ lignite-fired generating stations, working capital shall cover:

(i) Cost of coal or lignite for one and a half months for pit-head generating stations and two months for non-pit-head generating stations, corresponding to target availability;

(ii) Cost of oil for two months corresponding to target availability;

(iii) Cost of secondary fuel oil for two months corresponding to target availability;

(iv) Operation and Maintenance expenses for one month;

(v) Maintenance spares @ 1 per cent of the historical cost; and

(vi) Receivables for sale of electricity equivalent to two months of the sum of annual fixed charges and energy charges calculated on target availability; minus

(vii) Payables for fuel (including oil and secondary fuel oil) to the extent of one month of the cost of fuel calculated on target availability.

(b) In case of Gas Turbine/Combined Cycle generating stations, working capital shall cover:

(i) Fuel cost for one month corresponding to target availability duly taking into account the mode of operation of the generating station on gas fuel and / or liquid fuel;

(ii) Liquid fuel stock for fifteen (15) days corresponding to target availability;

(iii) Operation and maintenance expenses for one month;

(iv) Maintenance spares at 1 per cent of the historical cost; and

(v) Receivables for sale of electricity equivalent to two months of the sum of annual fixed charges and energy charges calculated on target availability, minus

(vi) Payables for fuel (including liquid fuel stock) to the extent of one month of the cost of fuel calculated on target availability.

(c) In case of hydro power generating stations, working capital shall cover:

(i) Operation and maintenance expenses for one month;

(ii) Maintenance spares at 1 per cent of the historical cost; and

(iii) Receivables for sale of electricity equivalent to two months of the annual fixed charges calculated on normative capacity index.

(d) In case of own generating stations, no amount shall be allowed towards receivables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations.

(e) Rate of interest on working capital shall be on normative basis and shall be equal to the short-term Prime Lending Rate of State Bank of India as on the date on which the application for determination of tariff is made.…"

ii) Working capital (for transmission licensees)

"50.6 Interest on working capital

50.6.1 The Transmission Licensee shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:

(a) One-twelfth of the amount of operation and maintenance expenses for such financial year; plus

(b) One-twelfth of the sum of the book value of stores, materials and supplies including fuel on hand at the end of each month of such financial year; plus

(c) One and a half months equivalent of the expected revenue from transmission charges at the prevailing tariffs; minus

(d) Amount, if any, held as security deposits from Transmission System Users.

50.6.2 Interest shall be allowed at a rate equal to the Short Term Prime Lending Rate of the State Bank of India as at the date on which the application for determination of tariff is made.

50.6.3 Interest shall be allowed on the amount held as security deposit from Transmission System Users at the Bank Rate as at the date on which the application for determination of tariff is made."

iii) Working capital (for wheeling of electricity)

"63.6 Interest on working capital

63.6.1 The Distribution Licensee shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:

(a) One-twelfth of the amount of Operation and Maintenance expenses for such financial year; plus

(b) One-twelfth of the sum of the book value of stores, materials and supplies including fuel on hand at the end of each month of such financial year; plus

(c) Two months equivalent of the expected revenue from wheeling charges at the prevailing tariffs; minus

(d) Amount, if any, held as security deposits under clause (b) of sub-section (1) of Section 47 of the Act from consumers and Distribution System Users.

63.6.2 Interest shall be allowed at a rate equal to the Short Term Prime Lending Rate of the State Bank of India as at the date on which the application for determination of tariff is made.

63.6.3 Interest shall be allowed on the amount held as security deposit from Distribution System Users at the Bank Rate as at the date on which the application for determination of tariff is made."

iv) Working Capital (Retail supply of electricity)

"76.8 Interest on working capital

76.8.1 The Distribution Licensee shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:

(a) One-twelfth of the amount of Operation and Maintenance expenses for such financial year; plus

(b) One-twelfth of the sum of the book value of stores, materials and supplies including fuel on hand at the end of each month of such financial year; plus

(c) Two months equivalent of the expected revenue from sale of electricity at the prevailing tariffs; minus

(d) Amount held as security deposits under clause (a) and clause (b) of subsection (1) of Section 47 of the Act from consumers and Distribution System Users; minus

(e) One month equivalent of cost of power purchased, based on the annual power procurement plan.

76.8.2 Interest shall be allowed at a rate equal to the Short Term Prime Lending Rate of the State Bank of India as at the date on which the application for determination of tariff is made.

76.8.3 Interest shall be allowed on the amount held as security deposit from Distribution System Users and consumers at the Bank Rate as at the date on which the application for determination of tariff is made."

The issues to be addressed as regards treatment of IWC are:

(i) Whether IWC should be allowed on normative basis or on actuals?

(ii) Whether working capital should be computed by taking into account both current assets and current liabilities, as being done presently?

(iii) Whether amount and stock of fuel oil/O&M expenses/maintenance spares/receivables specified in the existing Regulations should continue or, any change is required?

(iv) Whether maintenance spares should form a part of the working capital along with O&M expenses in the existing methodology?

(v) Whether stores and spares / repairs & maintenance / employees cost, insurance, security and most of the sub-elements under administrative expenses and most of the sub-elements under corporate office expenses included in O&M expenses should form a part of the working capital?

The above-mentioned issues and the merits and demerits of the options have been discussed below.

Currently, IWC is being allowed on a normative basis rather than actuals. Since IWC is treated as a controllable factor, IWC would have to continue to be allowed on normative basis. If IWC is allowed on actuals, it will amount to considering IWC as an uncontrollable factor. Since it is desired to improve the operational and financing efficiency in this aspect, **it is desirable to continue allowing IWC on normative basis**.

However, the experience in Maharashtra shows that the normative IWC computed in accordance with the MERC Tariff Regulations, works out to be very high as compared to the actual IWC expense incurred by the Utility, for generation and transmission business. In case of distribution licensees, on account of the large amount of consumers' security deposit lying with the licensee, the normative IWC works out to be nominal or negative in some cases. Hence, **there is a need to revise the norms considered for computing the working capital requirement for generation, transmission, distribution wire, and retail supply businesses, such that the normative levels reflect the actual working capital requirement more closely**, and do not result in unnecessarily increasing the expenses and hence, tariff charged to the consumers. Further, due to the increase in number of payment modes, including electronic billing and payment, the requirement of providing for two months receivables is also reduced. Also, in case of gas stations, the gas is delivered through pipelines and is not stored.

ABPS Infra has analysed monthly coal reports published by Central Electricity Authority (CEA) and compiled actual stock days for thermal power stations in Maharashtra.

Table 10: Average Coal Stock days (in days)

Station	Feb'09	Mar'09	Apr'09	May'09
Bhusawal TPS	5	6	2	1
Chandrapur TPS	2	2	3	4
Khaparkheda TPS	5	6	4	3
Paras TPS	3	3	2	1
Parli TPS	2	1	3	4
Nasik TPS	6	7	5	4
Koradi TPS	4	4	11	9
Dahanu TPS	8	8	10	7

Source: CEA website

It is clear from the above table that thermal generating stations are maintaining coal stock of around 10 days and are not maintaining the coal stock as specified in Regulations, which is two months. Hence, there is no need to provide for two months coal stock. The proposed norms for computation of working capital are given below:

<u>**Working capital (for Generating Stations)**</u>

The Working capital shall cover:

(a) For Coal based/Lignite-fired generating stations

i) Cost of coal or lignite for half (½) month for pit-head generating stations and one (1) months for non-pit-head generating stations, corresponding to the target availability;

ii) Cost of oil for one month corresponding to target availability;

iii) Cost of secondary fuel oil for one month corresponding to the target availability;

iv) Operation and Maintenance expenses for one month;

v) Maintenance spares @ 1% of the historical cost;

vi) Receivables equivalent to one and a half (1½) months of fixed and variable charges for sale of electricity computed on the target availability; and

vii) Payables for fuel (including oil and secondary fuel oil) to the extent of one month of the cost of fuel computed on target availability.

(b) For Gas Turbine/Combined Cycle generating stations

i) Fuel cost for half (½) month corresponding to the target availability duly taking into account the mode of operation of the generating station on gas fuel and liquid fuel;

ii) Liquid fuel stock for half (½) month;

iii) Operation and maintenance expenses for one (1) month;

iv) Maintenance spares at 1% of the historical cost;

v) Receivables equivalent to one and a half (1½) months of fixed and variable charges for sale of electricity computed on target availability.

vi) Payables for fuel (including oil and secondary fuel oil) to the extent of one month of the cost of fuel computed on target availability.

(c) Working capital (for hydro Stations)

The Working Capital shall cover:

(i) Operation and Maintenance expenses for one month;

(ii) Maintenance spares @ 1% of the historical cost;

(iii) Receivables equivalent to one and a half (1½) months of fixed charges for sale of electricity, computed on normative capacity index.

(d) Working capital (for transmission licensees)

(a) One-twelfth of the amount of operation and maintenance expenses for such financial year; plus

(b) One-twelfth of the sum of the book value of stores, materials and supplies at the end of each month of such financial year; plus

(c) One month equivalent of the expected revenue from transmission charges at the prevailing tariffs; minus

(d) Amount, if any, held as security deposits from Transmission System Users.

e) Working capital (for wheeling of electricity)

(a) One-twelfth of the amount of Operation and Maintenance expenses for such financial year; plus

(b) One-twelfth of the sum of the book value of stores, materials and supplies including fuel on hand at the end of each month of such financial year; plus

(c) One and half (1½) months equivalent of the expected revenue from wheeling charges at the prevailing tariffs; minus

(d) Amount, if any, held as security deposits from consumers and Distribution System Users.

f) Working Capital (Retail supply of electricity)

(a) One-twelfth of the amount of Operation and Maintenance expenses for such financial year; plus

(b) One-twelfth of the sum of the book value of stores, materials and supplies including fuel on hand at the end of each month of such financial year; plus

(c) One and half (1½) months equivalent of the expected revenue from sale of electricity at the prevailing tariffs; minus

(d) Amount, if any, held as security deposits from consumers and Distribution System Users; minus

(e) One month equivalent of cost of power purchased, based on the annual power procurement plan.

Interest on Working Capital is proposed to be treated as a controllable parameter and will be allowed on normative basis, as discussed above. It is important to mention here that in Andhra Pradesh and Delhi, where ROCE approach was followed, Interest on Working Capital (IWC) was inbuilt into the ROCE computations. Hence, no separate pass-through was allowed for IWC. However, in the both the States, tariff determination was done annually. Hence, variations vis-à-vis normative levels get adjusted annually. As discussed in Chapter-2, for Maharashtra, it is proposed to compute sharing of gains on account of controllable parameters, only at the end of the Control Period, while losses on account of controllable parameter need to be borne by the Utilities. Also, it should be noted that the entire difference between the normative interest on working capital and actual interest on working capital will be considered as an efficiency gain or loss, and shared accordingly. .

3.5 Contribution to Contingency Reserve

There are several developments, which have a very significant impact on the tariff, but cannot be envisaged at the time of tariff determination. For instance, natural calamities or situations on which the management has no control are situations, where it will be useful to have a Contingency Reserve. In this context, the MERC Tariff Regulations specifies contribution to contingency reserve for transmission, wires and supply business as under:

> *"50.7 Contribution to contingency reserves*
>
> *50.7.1 Where the Transmission Licensee has made an appropriation to the Contingencies Reserve, a sum not less than 0.25 per cent and not more than 0.5 per cent of the original cost of fixed assets shall be allowed towards such appropriation in the calculation of aggregate revenue requirement:*
>
> *Provided that where the amount of such Contingencies Reserves exceeds five (5) per cent of the original cost of fixed assets, no such appropriation shall be allowed which would have the effect of increasing the reserve beyond the said maximum:*
>
> *Provided further that the amount so appropriated shall be invested in securities authorized under the Indian T rusts Act, 1882 within a period of six months of the close of the financial year.*
>
> *50.7.2 The Contingency Reserve shall not be drawn upon during the term of the licence except to meet such charges as may be approved by the Commission as being:*
>
> *(a) Expenses or loss of profits arising out of accidents, strikes or circumstances which the management could not have prevented;*

(b) Expenses on replacement or removal of plant or works other than expenses requisite for normal maintenance or renewal;

(c) Compensation payable under any law for the time being in force and for which no other provision is made:

Provided that such drawal from Contingency Reserve shall be computed after making due adjustments for any other compensation that may have been received by the Licensee as part of an insurance cover."

"63.7.1 Where the Distribution Licensee has made an appropriation to Contingencies Reserve, a sum not less than 0.25 per cent and not more than 0.5 per cent of the original cost of fixed assets shall be allowed towards such appropriation in the calculation of wheeling charges:

Provided that where the amount of such Contingencies Reserves exceeds five (5) per cent of the original cost of fixed assets, no appropriation shall be made which would have the effect of increasing the reserve beyond the said maximum:

Provided further that the amount so appropriated shall be invested in securities authorized under the Indian T rusts Act, 1882 within a period of six months of the close of the financial year.

63.7.2 The Contingency Reserve shall not be drawn upon during the term of the licence except to meet such charges as may be approved by the Commission as being:

(a) Expenses or loss of profits arising out of accidents, strikes or circumstances which the management could not have prevented;

(b) Expenses on replacement or removal of plant or works other than expenses requisite for normal maintenance or renewal;

(c) Compensation payable under any law for the time being in force and for which no other provision is made:

Provided that such drawal from Contingency Reserve shall be computed after making due adjustments for any other compensation that may have been received by the Licensee as part of an insurance cover."

"76.9 Contribution to contingency reserves

76.9.1 Where the Distribution Licensee has made an appropriation to Contingencies Reserve, a sum not less than 0.25 per cent and not more than 0.5 per cent of the original cost of fixed assets shall be allowed towards such appropriation in the calculation of aggregate revenue requirement:

Provided that where the amount of such Contingencies Reserves exceeds five (5) per cent of the original cost of fixed assets, no appropriation shall be made which would have the effect of increasing the reserve beyond the said maximum:

Provided further that the amount so appropriated shall be invested in securities authorized under the Indian Trusts Act, 1882 within a period of six months of the close of the financial year.

76.9.2 The Contingency Reserve shall not be drawn upon during the term of the licence except to meet such charges as may be approved by the Commission as being:

(a) Expenses or loss of profits arising out of accidents, strikes or circumstances which the management could not have prevented;

(b) Expenses on replacement or removal of plant or works other than expenses requisite for normal maintenance or renewal;

(c) Compensation payable under any law for the time being in force and for which no other provision is made:

Provided that such drawal from Contingency Reserve shall be computed after making due adjustments for any other compensation that may have been received by the Licensee as part of an insurance cover."

The above clause provides for provisioning ranging from 0.25% to 0.5% of the original cost of fixed assets towards contingency reserves. Since the basic objective of this clause is to create a contingency fund, which can be drawn upon at times of natural calamity or situations over which the management has no control, it would be advisable that the contingency reserve of upto 0.25% to 0.50% of the original cost fixed asset be continued for the transmission, wires and retail supply business. As is the current practice, this provisioning should be subject to a ceiling of 5% of opening GFA. Further, the provisioning should be subject to submission of documentary proof of investment of the same in Government approved securities under the Indian Trusts Act, since it is in the best interest of the State that these funds be safely invested, and hence, be available as and when required. If this is not done, then there is a likely possibility that the Utility will utilise these funds to meet the daily expenses, and the contingency funds will not be available when needed. In case documentary evidence of proof of investment is not submitted within six months of the completion of the financial year, then the Commission may consider claw back of the impact of the contingency reserve on the tariff in the next year, and disallow creation of contingency reserve in future years.

3.6 Deposit work, consumer contribution and grant

The licensees undertake certain works on behalf of system users after obtaining a part or all of the funds from the consumers in the context of deposit works, through Service Line Charges and Service Connection Charges. Similarly, certain capital works are undertaken by utilising grants received from the State and Central Governments, including funds under RGGVY, APDRP, etc. However, the assets created by utilising such funds are included in the Gross Fixed Assets of the licensee. It is necessary to enunciate the principles for treatment of the expenses on such capital expenditure undertaken by utilising such funds from the Government and consumers.

It is proposed that:

a) O&M Expenses: Since the O&M expenses have to be incurred by the licensee, irrespective of who has funded the capital expenditure, it is proposed that the O&M expenses be considered in full even for such assets

b) Depreciation: Since depreciation is primarily being considered as a source of funds for repayment of the loans taken to finance the capital expenditure, the depreciation would have to be considered after deducting the funding from grants and deposit works from the total Gross Fixed Assets.

c) Return on Capital Employed: ROCE would be computed by applying ROCE rate on rate-base, which would be calculated by deducting the accumulated depreciation, funding from grants and deposit works from the total Gross Fixed Assets.

4 Norms and Principles for Determination of Generation Tariff

This Section deals with the issues related to the tariff applicable for Generating Companies supplying power to the Distribution Licensees in the State of Maharashtra.

The Maharashtra State Power Generating Company Limited (MSPGCL), Reliance Infrastructure Limited - Generation Business (RInfra-G) and The Tata Power Company Limited - Generation Business (TPC-G) are the Generating Companies in the State of Maharashtra, who own and operate coal thermal, gas and hydel based generating assets in the State and supply power to Distribution Licensees on a long-term basis. Further, MSPGCL has been operating various hydel generating stations, which are owned by the Government of Maharashtra (GoM) and have been handed over to MSPGCL for operation and maintenance. The brief summary of generating stations of MSPGCL, RInfra-G and TPC-G is given in the following Tables:

Table: Generating Stations of TPC-G

S.No	Station Name	Capacity	Unit Details	Type and Fuel	Status
1	Trombay	2027 MW	Unit-4 (1 x 150 MW)	Thermal - Oil	Stand By*
			Unit-5 (1 x 500 MW)	Thermal - Coal/Oil	Operational
			Unit-6 (1 x 500 MW)	Thermal - Oil/Gas	Operational
			Unit-7 (1 x 180 MW)	Thermal - Gas	Operational
			Unit-8 (1 x 250MW)	Thermal - Coal	Operational
2	Khopoli	72 MW		Hydel	Operational
3	Bhivpuri	75 MW		Hydel	Operational
4	Bhira	300 MW		Hydel	Operational
	Total	**2474MW**			

*Post commissioning of Unit-8, TPC-G has proposed to keep Unit-4 as stand-by

Table: Generating Station of RInfra-G

S.No	Station Name	Capacity	Unit Details	Type and Fuel	Status
1	Dahanu	500 MW	2 x 250 MW	Thermal - Coal	Operational

Table: Generating Stations of MSPGCL

Station / Unit	No of Units	Installed Capacity		Considering Derated Capacity	
		Capacity of each Unit in MW	Total Capacity in MW	Derated Capacity of each Unit in MW	Total Capacity in MW
Thermal					
Uran (Gas)			**852**		**852**
Unit 2,3,4	3	60	180	60	180
Unit 5,6,7,8	4	108	432	108	432
WHR_AO, WHR_BO	2	120	240	120	240
Khaperkheda			**840**		**840**
Unit 1,2,3,4	4	210	840	210	840
Paras	1	58	**58**	**55**	**55**
Bhusawal			**478**		**475**
Unit 1	1	58	58	55	55
Unit 2,3	2	210	420	210	420
Nasik			**910**		**880**
Unit 1,2	2	140	280	125	250
Unit 3,4,5	3	210	630	210	630
Parli			**690**		**670**
Unit 1,2	2	30	60	20	40
Unit 3,4,5	3	210	630	210	630
Koradi			**1080**		**1040**
Unit 1,2,3,4	4	115	460	105	420
Unit 5	1	200	200	200	200
Unit 6,7	2	210	420	210	420
Chandrapur			**2340**		**2340**
Unit 1,2,3,4	4	210	840	210	840
Unit 5,6,7	3	500	1500	500	1500
Sub-Total			**7190**		**7152**
Hydel					
Koyna			1956		1956
Vaitarna	1	60	60	60	60
Bhira	2	40	80	40	80
Tillari	1	66	66	66	66
Others			158		158
Sub-Total			**2320**		**2320**
Total			**9510**		**9472**

Note: In addition to above mentioned Units, MSPGCL has recently commissioned 250 MW Units each at Paras and Parli.

This Section of the Approach Paper deals with the issues related to determination of tariff for conventional generation projects.

4.1 Thermal Generating Stations

4.1.1 Capital Cost and Means of Finance

As per the existing practice, the Commission has been approving the capital cost for new generation projects after duly scrutinizing the reasonableness of the expenditure, i.e., actual expenditure incurred on the completion of the project. MSPGCL is implementing several expansion and new projects to bridge the demand supply gap and to meet the increasing electricity demand. Determining the normative per MW capital expenditure would be a complex issue as the Commission, in the next Control Period, has to decide tariff for existing projects and new projects as well as for Renovation & Modernisation (R&M) of existing projects. As discussed earlier, for new projects being developed under the competitive bidding route, the Commission will have to adopt the tariff quoted by the successful bidder, subject to the Competitive Bidding Guidelines being followed by the Procurer.

Currently, the Commission accords the final approval for tariff after commissioning of the project based on actual expenditure incurred on completion of the project subject to prudence check, which forms the basis for determination of the Capital Cost of the Project. The Capital Cost of the project thus determined also includes capitalised initial spares subject to ceiling norms as percentage of original cost for the coal-based/lignite fired, gas turbine/combined cycle and hydro power generating stations.

The Tariff Policy notified by the Government of India stipulates that all future requirement of power should be procured competitively by Distribution Licensees except in cases of expansion of existing projects or where there is a State controlled/owned Company as an identified developer and in such cases, the Regulatory Commissions will have to resort to tariff determination based on norms. Further, for expansion of generating capacity by private developers to one-time addition of not more than 50% of the existing capacity for qualifying under the above said normative tariff determination. Even for Public Ssector Generating Companies, the Tariff Policy provides that tariff of all new generation projects should be decided on the basis of competitive bidding after a period of five years or when the Regulatory Commission is satisfied that the situation is ripe to introduce such competition.

Under these circumstances, the scope for approving the Capital Cost and Means of Finance will be limited, as the Distribution Licensees will have to gradually move towards procurement of power only on competitive bidding basis. However, at this stage, the Commission may have to approve the Capital Cost and Means of Finance for following types of Projects:

- Expansion Project of Generating Companies
- Renovation and Modernisation Project of Generating Companies

The present methodology of final approval of capital cost based on actual capital expenditure subject to prudence check is proposed to be continued.

Under this mechanism, the Generating Company should file a separate Petition for approval of Tariff on 'cost-plus' basis after achieving Commercial Operation Date (COD) of the Project. While filing a Petition for approval of Tariff, the Generating Company should submit the estimated Project Cost, original schedule for the Project, actual completed Project Cost based on audited accounts and actual schedule for the Project along with reasons for cost over-run and delay (time over-run), if applicable. The cost over-run and delay in achieving COD of the Project needs to be considered on case-to-case basis based on justification provided by the Generating Company.

As discussed in Section 3 of this Approach Paper, it is proposed to adopt the method of giving Return on Capital Employed (RoCE) rather than the Return on Equity (RoE) approach being followed presently.

4.1.2 Components of Tariff

The tariff determined by the Commission is the prime source of revenue for a generating company and hence, the mechanism of cost recovery needs to be designed to ensure cost recovery at normative levels prescribed by the Commission.

Typically, the tariff for thermal generating stations has two components, i.e., fixed (capacity) charge and variable charge. The variable charge component is intended to cover the fuel costs for the primary and secondary fuel consumption at normative parameters.

The Central Electricity Regulatory Commission (CERC) in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has stipulated the following elements as a part of the Annual Fixed Cost:

(a) Return on equity;
(b) Interest on loan capital;
(c) Depreciation;
(d) Interest on working capital;
(e) Operation and maintenance expenses;
(f) Cost of secondary fuel oil (for coal-based and lignite fired generating stations only);
(g) Special allowance in lieu of R&M or separate compensation allowance, wherever applicable.

It may be observed from the above that apart from other elements of annual fixed cost, CERC has also considered cost of secondary fuel oil as a part of the fixed cost. However, since the consumption of the secondary fuel oil is linked with generation and the norm of secondary fuel oil is also specified in terms of per unit of generation, it is suggested that the secondary fuel oil consumption may not be included as a part of the fixed cost and may be considered as a part of the variable cost as per the existing practice in Maharashtra.

It is suggested that the fixed charge (capacity charge) shall comprise the following elements:

- Depreciation, including Advance Against Depreciation
- O&M Expenses
- Return on Capital Employed
- Interest on Working Capital

  Less:
- Less Other Income

4.1.3 Fixed Cost Recovery

The two alternative mechanisms that can be adopted for recovery of full fixed cost are as follows:

- Fixed Cost Recovery linked to Plant availability
- Fixed Cost Recovery linked to Plant Load Factor or Actual Generation

Fixed cost recovery linked to plant availability is a tested method which has been widely adopted by CERC (in both the earlier Tariff Regulations) as well as other SERCs. In this regard, MERC Tariff Regulations stipulates target availability of 80% for recovery of full fixed cost for all thermal stations. The existing MERC Tariff Regulations stipulating fixed charge recovery linked to plant availability factor is reproduced below:

> *"33.1.1 Availability*
>
> *(a) Target availability for full recovery of annual fixed charges shall be 80 per cent*
>
> *(c) Target Plant Load Factor for incentive in accordance with Regulation 37 shall be 80 per cent"*

While computing the Availability, the actual ability of the Station to generate should be considered after taking into consideration the loadability of machines and fuel related aspects, rather than considering plant availability on the basis of machine availability which considers only the readiness of machine/equipments for generating electricity but in reality, the plant may not be available due to inter-alia, lack of fuel or loadability issues. Normally, in case of supply shortage scenario, the PLF should be almost equivalent to plant availability, since the plants would not be backed down and would be utilised fully when available. In the existing MERC Tariff Regulations, Availability has been defined as actual availability after taking into account the availability of fuel. In view of the above, it is proposed that the Definition of Availability may be continued as defined in existing Regulations as follows:

> *"**Availability**" in relation to a thermal generating station for any period means the average of the daily average declared capacities for all the days during that period expressed as a percentage of the installed capacity of the generating station minus normative auxiliary consumption in MW, as specified in the Regulations, and shall be computed in accordance with the following formula …"*
>
> *"**Declared Capacity**" means-*
>
> *(i) for a thermal generating station, the capability of the generating station to deliver ex-bus electricity in MW declared by such generating station in relation to any period of the day or whole of the day, duly taking into account the availability of fuel;*

provided that in case of a gas turbine generating station or a combined cycle generating station, the generating station shall declare the capacity for units and modules on gas fuel and liquid fuel separately, and these shall be scheduled separately. Total declared capacity and total scheduled generation for the generating station shall be the sum of the declared capacity and scheduled generation for gas fuel and liquid fuel for the purpose of computation of availability and Plant Load Factor respectively."

However, in case the Generating Company has made adequate arrangements for procurement of fuel and if there is reduction in supply of fuel due to shortage of fuel, for instance, in case of actual gas supply lower than the gas linkage, the reduction in availability due to shortage of fuel needs to be appropriately considered for allowing fixed cost recovery, as reduction in fuel supply due to industry-wide shortage is an uncontrollable factor for the Generating Company.

The Plant Availability is linked to the vintage and the technology of the Plant. As the Plant becomes older, the time taken for overhaul of the Plant increases and the Availability of the Generating Station reduces. CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009, has specified lower availability norm for some Units of Neyveli Lignite Corporation [TPS-I (72%) and TPS-II, Stage I & II (75%)] and for some of the stations of Damodar Valley Corporation (DVC) [Durgapur TPS (74%), Bokaro TPS (75%), Chandrapur TPS (60%)] while for other Generating Stations, CERC has specified the Availability norm of 85% for thermal generating stations, as compared to the earlier norm of 80%.

The normative Plant Availability approach ensures that the Generating Company is able to recover its fixed cost, if the plant is available for generation. It is beneficial for those plants whose variable cost is high and their generation may be curtailed under merit order despatch principles. However, this may be disadvantageous to the Distribution Licensee as it has to pay the fixed cost irrespective of the actual drawal. However, in principle, fixed cost recovery should not be linked to generation, and only variable cost recovery should be linked to the generation.

Fixed cost recovery based on actual generation or PLF has not been adopted by the Regulatory Commissions for conventional projects. However, most Regulatory Commissions, while designing single-part tariff for renewable energy based projects, have linked the cost recovery with the actual generation or plant load factor (Capacity utilisation factor).

CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has stipulated the following principles for recovery of fixed charge including the incentive component:

"(a) Generating stations in commercial operation for less than ten (10) years on 1st April of the financial year :
AFC x (NDM / NDY) x (0.5 + 0.5 x PAFM / NAPAF) (in Rupees);

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

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

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

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

At this stage, it is proposed to continue the existing practice of fixed cost recovery based on the normative plant availability. Accordingly, full fixed charge recovery should be allowed at normative plant availability specified by the Commission. Recovery of fixed charges below the normative target availability should be on pro-rata basis and accordingly at zero availability, no recovery of fixed charges should be allowed.

It is proposed to specify the normative availability for existing stations after duly considering the actual availability achieved during the recent past, technology, configuration, size and benchmarking of availability of similar size and similar vintage Units in the country. However, for new generating stations, the normative availability for recovery of fixed costs may be specified as 85%, as specified by CERC in its CERC

(Terms and Conditions of Tariff) Regulations, 2009. Further, as regards incentive, it is proposed to provide incentive linked to actual generation.

As the demand of Distribution Licensees varies during different months of the year, it may be possible that during certain months, though the generating station is available, the Distribution Licensee is unable to off-take the power, either partly or fully. Under such circumstances, the Generating Company should explore the option of selling such surplus power (not required by Distribution Licensees), provided the rate for sale of power to other sources should not be less than the energy charges payable by Distribution Licensee. In such cases, if the Generating Company is able to sell such power not off-taken by the Distribution Licensee, certain proportion (say around 50%) of the recovery in excess of energy charges payable by the Distribution Licensee should be utilised for reducing the fixed cost liability of the distribution licensee. It is important to allow the Generating Company to retain certain proportion of recovery in excess of energy charges payable by the Distribution Licensee, say around 50%, to incentivise the Generating Company to make adequate efforts to sell the power not availed by the Distribution Licensee. However, it is suggested that the above mechanism of sharing excess energy charges shall be applicable for such generating stations only for which the Commission determines the tariff in accordance with the MYT Regulations. The mechanism of sharing excess energy charges in case of Distribution Licensees procuring power through competitive bidding under Case-I and Case-II route shall be governed by the PPA executed between them.

4.1.4 Norms of Operation

Apart from Target Availability for recovery of Fixed Costs, the other Performance norms to be specified for a thermal generating station include:

- **Station Heat Rate**
- **Auxiliary Power Consumption**
- **Secondary Fuel Consumption**
- **Transit Losses**

4.1.5 Norms for New Generating Stations to be commissioned after the Date of Effectiveness of the MERC MYT Regulations

4.1.5.1 Relaxed Norm during Stabilisation Period

The existing MERC Tariff Regulations stipulate separate norms for some of the operational parameters of the thermal generating stations such as Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption, during stabilization period. However, CERC in its third Amendment to Tariff Regulations, viz., CERC (Terms and Conditions of Tariff) (Third Amendment) Regulations, 2007, has amended this provision and specified that

> *"The stabilization period and relaxed norms applicable during stabilization period shall cease to apply from April 1, 2006"*.

Further, CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009, which has been notified recently, has again not stipulated any relaxed norm for the stabilisation period.

In view of the above, it is proposed not to specify the stabilization period and relaxed norms during stabilization period for new thermal generating stations to be commissioned after the date of effectiveness of the MERC MYT Regulations.

4.1.5.2 Station Heat Rate

For new generating stations to be commissioned after the date of effectiveness of the Regulations, the Station Heat Rate norm is proposed in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 for various technologies and Unit sizes as well as considering the technological advances and improvement, with manufacturers' committing design heat rates stipulated as under:

a) Coal-based and lignite-fired Thermal Generating Stations

= 1.065 X Design Heat Rate (kcal/kWh)

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

Provided that the design heat rate shall not exceed the following maximum design unit heat rates depending upon the pressure and temperature ratings of the Units:

Pressure Rating (kg/cm2)	150	170	170	247	247
SHT/RHT (^{0}C)	535/535	537/537	537/565	537/565	565/593
Type of BFP	Electrical Driven	Turbine driven	Turbine driven	Turbine driven	Turbine driven
Max Turbine Cycle Heat rate (kcal/kWh)	1955	1950	1935	1900	1850
Min. Boiler Efficiency					
Sub-Bituminous Indian Coal	0.85	0.85	0.85	0.85	0.85
Bituminous Imported Coal	0.89	0.89	0.89	0.89	0.89
Max Design Unit Heat rate (kcal/kWh)					
Sub-Bituminous Indian Coal	2300	2294	2276	2235	2176
Bituminous Imported Coal	2197	2191	2174	2135	2079

However, in case pressure and temperature parameters of a Unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken:

Note:

For generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average station heat rate.

b) Gas-based / Liquid-based thermal generating Unit(s)/block(s)

= 1.05 X Design Heat Rate of the unit/block for Natural Gas and RLNG (kcal/kWh)

= 1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kcal/kWh)

Where the Design Heat Rate of a Unit shall mean the guaranteed heat rate for a Unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure.

4.1.5.3 Auxiliary Consumption

For new generating stations to be commissioned after the date of effectiveness of the MYT Regulations, the auxiliary consumption norm is proposed in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 for various technologies and Unit sizes as under:

(a) Coal-based generating stations:

Auxiliary consumption	With Natural Draft cooling tower or without cooling tower
(i) 200 MW series	8.5%
(ii) 500 MW & above	
Steam driven boiler feed pumps	6.0%
Electrically driven boiler feed pumps	8.5%

Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%.

(b) Gas Turbine/Combined Cycle generating stations:

(i) Combined cycle : 3.0%

(ii) Open cycle : 1.0%

(c) Lignite-fired thermal generating stations:

(i) All generating stations with 200 MW sets and above:

The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal based generating stations above. Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal based generating stations at above.

As regards the auxiliary consumption for Flue Gas Desulphurisation (FGD), CERC, in its (Terms and Conditions of Tariff) Regulations, 2009 has not specified any specific or relaxed norm. RInfra-G has commissioned the FGD Plant at DTPS in FY 2007-08 and TPC-G has commission the FGD Plant at Unit-8 in FY 2008-09. The Commission, in its Orders while determining the tariff of DTPS for FY 2007-08 and FY 2008-09 has approved the auxiliary consumption for FGD separately in addition to normative auxiliary consumption applicable for the station. It is proposed to continue with the same methodology of separately approving the auxiliary consumption for FGD plant over and above the normative auxiliary consumption for the station till the actual performance data for at least 2-3 years is available in this regard. Therefore, it is suggested that auxiliary consumption for stations which commissions the FGD Plant after the date of effectiveness of the MERC MYT Regulations may be approved on case to case basis.

4.1.5.4 Transit Loss

For new generating stations to be commissioned after the date of effectiveness of the MYT Regulations, the transit loss norm is proposed in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 as under:

> Transit losses for coal based generating stations, as a percentage of quantity of coal dispatched by the coal supply company during the month shall be as given below:
>
> i. Pit head generating stations - 0.2%
>
> ii. Non-pit head generating stations - 0.8%

The above norms may be made applicable for all types of indigenous coal including washed coal. As regards the transit losses on imported coal, CERC, in its (Terms and Conditions of Tariff) Regulations, 2009 has not specified any norms. Further, it may be noted that RInfra-G also reports transit loss on imported coal, whereas TPC-G as well as MSPGCL have never reported any such losses on imported coal. The Commission, in its latest APR Order for RInfra-G, has disallowed transit losses on imported coal and directed RInfra-G to procure imported coal on delivery basis. Therefore, it is suggested that no transit losses may be approved for imported coal for new generating stations to be commissioned after the date of effectiveness of the MYT Regulations and Generting Companies should procure imported coal on delivery basis.

4.1.5.5 Secondary Fuel Oil Consumption

For new generating stations to be commissioned after the date of effectiveness of the MERC MYT Regulations, the auxiliary consumption norm is proposed in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 as under:

(a) **Coal-based generating stations :** 1.0 ml/kWh

(b) **Lignite-Fired generating stations except stations based on CFBC technology :** 2.0 ml/kWh

(c) **Lignite-Fired generating stations based on CFBC technology :** 1.25 ml/kWh

4.1.6 Norms for Existing Generating Stations – Existing before the date of effectiveness of MERC Tariff Regulations, 2005.

As regards the performance parameters to be specified for the existing generating stations of MSPGCL, the Commission, in its MYT Order for the first Control Period of 3 years from FY 2007-08 to FY 2009-10 specified the trajectory for various performance parameters after benchmarking MSPGCL's generating stations with other generating stations of similar capacity and vintage. MSPGCL challenged the Commission's MYT Order before the Honourable Appellate Tribunal for Electricity (ATE). The ATE dealt with the above issues vide its Judgment dated April 10, 2008 in Appeal No.s 86 and 87 of 2007 and ruled as under:

- ATE directed the Commission to engage an appropriate agency/ies either on its own or through MSPGCL, to carry out a study in a time bound manner (preferably within three months) to reasonably assess the achievable heat rate of the plants owned by MSPGCL and to suggest measures to improve the heat rates over a period of time. ATE further directed the Commission to determine the heat rate based on the outcome of the study and directed that the pre-existing tariffs may be continued, subject to truing up based on the revised heat rates, when available.
- ATE directed the Commission to take into consideration the independent study and reset the operating parameters, viz., transit loss of coal, station heat rate, auxiliary consumption, and specific oil consumption, and align its Regulations by prescribing achievable norms and not merely ideal norms. ATE also advised the Commission to ensure that deliberate inefficiencies on the part of the Utility are not passed on to the consumers.

For assessment of actual and achievable performance parameters, the Commission has appointed M/s Central Power Research Institute (CPRI) to carry out a detailed study of the various performance parameters and based on the findings of the study and after due regulatory process. Since the study of CPRI is expected to be completed by August

2009, ABPS Infra suggests that for existing stations of MSGPCL, the norms may be approved after considering the study of the CPRI and further regulatory process in that regard.

The Commission has also emphasised on benchmarking the performance parameters for the generating stations in the State of Maharashtra with their own past performance as well as with the generating stations in other States and Central Generating Stations which are of similar vintage, technology, configuration and operating performance. The detailed comparison of these parameters is discussed in the subsequent paragraphs.

The generating units of TPC-G have the capability to fire multiple fuels, whereas most of the other generating stations in the State of Maharashtra and other States do not have the capability to fire multiple fuels. Therefore, the comparison of TPC-G's generation stations with other generating stations would not be appropriate, and hence, ABPS Infra has considered the past performance of generating Units of TPC-G for stipulating various performance parameters for the next Control Period. However, for RInfra-G,

For RInfra-G Dahanu station, ABPS Infra has carried out the detailed comparison of performance parameters with similar size and similar vintage stations is discussed in the subsequent paragraphs.

4.1.6.1 Station Heat Rate

Heat rate is an indicator of power plant efficiency and depends on the vintage, generation capacity, and technology of the generating unit. In the existing MERC Tariff Regulations, the Commission has specified the following norms for the Gross Station Heat Rate:

Coal Based Power Plants

Particulars	**200/210/250 MW sets**	**500 MW and above sets**
During stabilization period	2600 kcal/kWh	2550 kcal/kWh
Subsequent period	2500 kcal/kWh	2450 kcal/kWh

Note 1

In respect of 500 MW and above Units, where the boiler feed pumps are electrically operated, the gross Station Heat Rate shall be 40 kcal/kWh lower than the Station Heat Rate indicated above.

Note 2

For generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average station heat rate.

Lignite based Power Plants

For lignite fired power plants, the Commission has specified the multiplying factors, depending upon the moisture content in the lignite, for deriving the heat rate from that applicable for coal based thermal power plants, as under:

i. For lignite having 50% moisture: Multiplying factor of 1.10
ii. For lignite having 40% moisture: Multiplying factor of 1.07
iii. For lignite having 30% moisture: Multiplying factor of 1.04
iv. For other values of moisture content, multiplying factor shall be prorated for moisture content between 30-40 and 40-50 depending upon the rated values of multiplying factor for the respective range given under sub-clauses (i) to (iii) above.

Gas Turbine / Combined cycle generating stations

	Advance Class Machines	E/EA/EC/E2 Class machines
Open Cycle	2685 kcal /kWh	2830 kcal/kWh
Combined Cycle	1850 kcal/kWh	1950 kcal/kWh

Small Gas Turbine generating stations:

	Advance Class Machines	E/EA/EC/E2 Class machines
Open Cycle	3125 kcal/kWh	1.02x3125 kcal/kWh
Combined Cycle	2030 kcal/kWh	1.02x2030 kcal/kWh

It is proposed to retain the above norms of station heat rate for the Stations that have declared commercial operation after the effectiveness of the MERC Tariff Regulations and before the date of the effectiveness of the MERC MYT Regulations.

CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has considered the technology, configuration, and operating level of different power plants and has accordingly fixed different heat rates for thermal and gas turbine/combined cycle power plants. The practice followed by CERC covers all the dimensions of a generating unit, which may have a bearing on the station heat rate. The experience of many other SEBs/SERCs and the data available in this regard suggests that the various factors affecting the Heat Rate are vintage, size, past generating history, past maintenance practices, condition of plant, etc.

Clause 5.3(f) of the Tariff Policy stipulates:

> ***"Operating Norms***
>
> *Suitable performance norms of operations together with incentives and dis-incentives would need be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in para 5.3 (h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance. The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized.*
>
> *The Central Commission would, in consultation with the Central Electricity Authority, notify operating norms from time to time for generation and transmission. The SERC would adopt these norms. In cases where operations have been much below the norms for many previous years, the SERCs may fix relaxed norms suitably and draw a transition path over the time for achieving the norms notified by the Central Commission."*

ABPS Infra has primarily emphasised on the comparison of the past performance of the generating stations in the State of Maharashtra and also compared the performance of the stations in the State with generating stations in another States.

The summary of the past performance of the thermal generating stations of TPC-G, RInfra-G and MSPGCL in the context of Station Heat Rate is shown in the Table below:

Table: Actual and Approved Station heat Rate of Exiting Stations/Units (kcal/kWh)

Station	Unit	Fuel	Capacity (MW)	Actual						Approved				
				2004-05	2005-06	2006-07	2007-08	Average (04-08)	2008-09*	2004-05	2005-06	2006-07	2007-08	2008-09
Trombay	Unit 4	Oil	150	2555	2564	2517	2497	2533	2522	2555	2564	2560	2565	2570
	Unit 5	Oil	500	2456	2458	2488	2567	2492	2539	2456	2458	2484	2500	2494
	Unit 6	Oil	500	2328	2322	2339	2306	2324	2353	2328	2322	2373	2400	2400
	Unit 7	Gas	180	1977	1971	1971	2001	1980	1968	1977	1971	1977	1992	1971
Dahanu	Unit-1 & -2	Coal	2 x 250	2272	2286	2278	2289	2281	2308	2319	2286	2500	2500	2500
Khaparkheda		Coal	840	2642	2600	2612	2755	2652	2783	2725	2725	2644	2556	2561
Paras		Coal	58	3340	3197	3261	3291	3272	3243	3200	3197	3105	3106	3105
Bhusawal		Coal	478	2668	2636	2666	2914	2721	2933	2735	2636	2561	2649	2654
Nasik		Coal	910	2594	2649	2672	2659	2644	2807	2663	2649	2584	2648	2653
Parli		Coal	690	2647	2662	2678	2779	2692	2871	2649	2662	2573	2652	2657
Koradi		Coal	1080	2950	2978	2997	3249	3044	3280	2996	2978	2907	2786	2792
Chandrapur		Coal	2340	2660	2611	2600	2599	2618	2713	2502	2611	2480	2545	2551
Uran Gas		Gas	852	1992	2026	1969	1973	1990	2000	1966	2026	1950	1980	1980

*FY 2008-09 figures are provisional true up values.

TPC-G

The average station heat rate of the generating Units of TPC-G as listed in the above Table for the last four years (i.e., FY 2004-05 to FY 2007-08) has been lower than the normative station heat rate specified by the Commission for the first Control Period, except for Unit-5. The present norms of station heat rate are comfortable and are being met by all the generating Units of TPC-G except Unit-5.

The generating Units of TPC-G have the capability to fire multiple fuels, whereas most of the other generating stations in the State of Maharashtra and other States do not have the capability to fire multiple fuels. Therefore, the comparison of TPC-G's generation stations with other generating stations would not be appropriate, and hence, ABPS Infra has considered the past performance of generating Units of TPC-G for stipulating the Station Heat Rate for the next Control Period.

As the actual station heat rate of most of the generating Units of TPC-G has been lower than the normative station heat rate, it is suggested that the station heat rate for the next Control Period may be stipulated based on the average heat rate actually achieved during the period from FY 2004-05 to FY 2007-08. The benefits of a Multi Year Tariff regime can be realised only if the operational norms are revised at the end of the Control Period to reflect the better than normative performance during the Control Period, since the Generating Company has already been allowed to retain the efficiency gains due to the better than normative performance during the first Control Period. In this manner, the tariffs can be reduced, and the Generating Company can be incentivised to further improve their performance and retain the consequent efficiency gains during the second Control Period.

ABPS Infra has proposed to consider the average heat rate achieved during the period from FY 2004-05 to FY 2007-08 as heat rate at middle of this period and a degradation factor of 0.2% per year for Unit-4, Unit-5 and Unit-6 while specifying the heat rate norm for the next Control Period. The normative station heat rate proposed for TPC-G's generating Units are given in the following Table:

Table: Station Heat Rate Norm for Existing Units of TPC-G (kcal/kWh)

Particulars	Station Heat Rate				
	FY 2010-11	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15
Unit-4	2549	2554	2559	2564	2569
Unit-5	2507	2512	2517	2522	2527
Unit-6	2338	2342	2347	2352	2357
Unit-7	1971	1971	1971	1971	1971

RInfra-G

The average station heat rate of the Dahanu Thermal Power Station (DTPS) of RInfra-G for the last four years (i.e., FY 2004-05 to FY 2007-08) has been lower than the normative value of station heat rate specified by the Commission for the first Control Period. The station heat rate achieved by DTPS and some of the other stations in the country of similar vintage and Unit size is given in the following Table:

Table: Actual Station Heat Rate achieved by DTPS and other Units of similar size and vintage

Parameter						SHR (kcal/kWh)			
Generating Stations	**State**	**Unit Capacity (MW)**	**COD**	**Type**	**Age**	**04-05**	**05-06**	**06-07**	**07-08**
GHTP	Punjab	2x210	1998	Coal	11	2402	2407	-	-
Ropar	Punjab	6x210	1984-93	Coal	16-25	2500	2541	-	-
Dahanu	Maharashtra	2x250	1995	Coal	14	2272	2286	2278	2289
Gandhi Nagar	Gujarat	211	1998	Coal	11		2694	2804	2520
Wanak Bori	Gujarat	210	1998	Coal	11		2763	2485	2474
Dadri Thermal	Uttar Pradesh	4x210	1991-94	Coal	21-24	2434	2421	2414	
Budge	West Bengal	2x250	1997-99	Coal	10-12		2460	2468	2472

Budge									

Source:SERC Tariff Orders and ABPS Infra Analysis

ABPS Infra has compared the station heat rate of DTPS with that of generating stations in other States having Unit size and vintage comparable to Unit size of 250 MW of DTPS. It may be observed from the above Table that DTPS has performed much better than other generating stations in the country of comparable Unit size and vintage. In accordance with the MERC Tariff Regulations, RInfra-G has been allowed to retain its share of the efficiency gains due to the better than normative heat rate achieved by DPTS over the first Control Period.

As DTPS has achieved lower station heat rate as compared to other similarly placed stations, it is suggested that the station heat rate for the next Control period may be stipulated based on the past performance of the station. ABPS Infra has considered average heat rate achieved during the period from FY 2004-05 to FY 2007-08 as the opening level of heat rate and a degradation factor of 0.2% per annum for specifying the norm for the next Control Period. The station heat rate norm proposed for DTPS are given in the following Table:

Table: Station Heat Rate Norm for RInfra-G's DTPS (kcal/kWh)

Particulars	Station Heat Rate				
	FY 2010-11	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15
DTPS	2295	2300	2304	2309	2313

MSPGCL

The average station heat rate for most of the generating stations of MSPGCL for last four years (i.e., FY 2004-05 to FY 2007-08) has been higher than the normative station heat rate specified by the Commission for the first Control Period. As discussed previously, the station heat rate of existing stations of MSPGCL has to be approved after considering the outcome of the study being carried out by CPRI.

4.1.6.2 Auxiliary Consumption

The existing norms of auxiliary consumption specified in MERC Tariff Regulations are as under:

a) Coal-based Generating Stations

Auxiliary consumption	With Cooling Tower	Without Cooling Tower
(i) 200 MW series	9.00%	8.50%
(ii) 500 MW series	7.50%	7.00%
Steam driven boiler feed pumps	7.50%	7.00%
Electrically driven boiler feed pumps	9.00%	8.50%

b) Gas Turbines/Combined Cycle Generating Stations

i. Combined cycle : 3.0%

ii. Open cycle : 1.0%

c) Lignite-fired thermal power generating stations:

The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations specified above.

Note:

During stabilization period, normative auxiliary consumption shall be reckoned at 0.5 percentage point more than the norms indicated at (a), (b) and (c) above.

The norms set by the Commission takes into consideration the Unit size and technology of the plant. It is proposed to retain the above norms for auxiliary consumption for the Stations that have declared commercial operation after the effective date of the MERC Tariff Regulations and before the effective date of the MYT Regulations.

As discussed earlier, ABPS Infra has considered benchmarking as a platform for setting the norms for the Generating stations of the State of Maharashtra. ABPS Infra has primarily compared the past performance of the generating stations in the State of Maharashtra with the performance of generating stations in another States. The following table shows the past performance of the Thermal generating stations of TPC-G, RInfra-G and MSPGCL in the context to Auxiliary Consumption:

Table: Auxiliary consumption (%)

Generating company	Station	Fuel	Capacity (MW)	Actual 2004-05	Actual 2005-06	Actual 2006-07	Actual 2007-08	Actual Average (04-08)	Actual 2008-09*	Approved 2004-05	Approved 2005-06	Approved 2006-07	Approved 2007-08	Approved 2008-09
TPC-G	Trombay	Oil	150	7.79	8.32	7.47	7.39	7.74	7.49	7.79	8.32	7.73	8.00	8.00
		Oil	500	5.00	5.12	4.93	4.87	4.98	4.79	5.00	5.12	5.14	5.50	5.50
		Oil	500	3.20	3.31	3.43	3.07	3.25	3.26	3.20	3.31	3.39	3.50	3.50
		Gas	180	2.31	2.29	2.38	2.37	2.34	2.42	2.31	2.29	2.33	2.75	2.75
RInfra-G	Dahanu	Coal	2 x 250	7.53	7.59	7.64	7.67	7.61	8.50	7.34	7.59	8.50	8.50	8.50
MSPGCL	Khaparkheda	Coal	840	8.88	9.58	9.06	8.90	9.11	9.26			8.50	8.50	8.50
	Paras	Coal	58	10.50	9.58	10.47	11.39	10.49	11.53			9.70	9.70	9.70
	Bhusawal	Coal	478	9.69	9.29	9.87	10.07	9.73	10.00			9.75	9.75	9.75
	Nasik	Coal	910	9.21	9.07	9.16	9.08	9.13	9.54			9.00	9.00	9.00
	Parli	Coal	690	8.99	9.20	9.48	10.06	9.43	10.56			9.00	9.00	9.00
	Koradi	Coal	1080	9.93	9.64	9.99	10.19	9.94	10.75			9.80	9.80	9.80
	Chandrapur	Coal	2340	7.72	7.79	8.37	7.40	7.82	7.80			8.50	7.80	7.80
	Uran Gas	Gas	852	2.29	2.27	2.13	2.17	2.22	2.25			2.30	2.40	2.40

*FY 2008-09 actual figures are provisional values based on actual for first six months and estimated for remaining months.

TPC-G

The average auxiliary consumption for the generating Units of TPC-G as listed in the above Table for the last four years (i.e., FY 2004-05 to FY 2007-08) has been lower than the normative value of auxiliary energy consumption specified by the Commission for the first Control Period. The present norms of auxiliary consumption are comfortable and are being met by all the generating Units of TPC-G.

As the generating Units of TPC-G has achieved lower than normative auxiliary energy consumption, it is suggested that the auxiliary consumption for the next Control period may be stipulated based on past performance.

The benefits of a Multi Year Tariff regime can be realised only if the operational norms are revised at the end of the Control Period to reflect the better than normative performance during the Control Period, since the Generating Company has already been allowed to retain the efficiency gains due to the better than normative performance during the first Control Period. In this manner, the tariffs can be reduced, and the Generating Companies can be incentivised to further improve their performance and retain the consequent efficiency gains during the second Control Period.

The auxiliary consumption norm proposed for TPC-G Units for the next Control Period based on the average auxiliary consumption for the period from FY 2004-05 to FY 2007-08 are as under:

Table: Auxiliary consumption Norm for TPC-G Thermal Units (%)

Particulars	Auxiliary Consumption
Unit-4	7.74
Unit-5	4.98
Unit-6	3.25
Unit-7	2.34

RInfra-G

The average auxiliary consumption of DTPS for the last four years (i.e., FY 2004-05 to FY 2007-08) has been lower than the normative value of auxiliary energy consumption specified by the Commission for the first Control Period. The auxiliary consumption achieved by DTPS and some of the other stations in the country of similar vintage and Unit size is given in the following Table:

Table: Actual Auxiliary Energy Consumption achieved by DTPS and other similar size and vintage units

Parameter						Auxiliary Consumption (%)			
Generating Stations	**State**	**Unit Capacity (MW)**	**COD**	**Type**	**AGE**	**04-05**	**05-06**	**06-07**	**07-08**
GHTP	Punjab	2x210	1998	Coal	11	9.58	8.97	8.79	-
Ropar	Punjab	6x210	1984-93	Coal	16-25	8.57	8.51	8.38	8.35
Dahanu	Maharashtra	2x250	1995	Coal	14	7.53	7.59	7.64	7.67
Gandhi Nagar	Gujarat	211	1998	Coal	11		8.61	9.85	9.19
Wanak Bori	Gujarat	210	1998	Coal	11		8.76	8.94	8.48
Dadri Thermal	Uttar Pradesh	4x210	1991-94	Coal	21-24	7.34	7.35	7.61	7.22
Budge Budge	West Bengal	2x250	1997-99	Coal	10-12	9.17	8.32	8.13	7.91

Source:SERC Tariff Orders and ABPS Infra Analysis

ABPS Infra has compared the auxiliary consumption of DTPS with that of generating stations in other States having Unit size and vintage comparable to Unit size of 250 MW of DTPS. It may be observed from the above Table that DTPS has performed much better than other generating stations in the country of comparable Unit size and vintage. In accordance with the MERC Tariff Regulations, RInfra-G has been allowed to retain its share of the efficiency gains due to the better than normative auxiliary consumption achieved by DPTS, over the first Control Period.

Considering the actual auxiliary consumption achieved during the past years, the proposed Auxiliary Consumption norm is 7.61%. RInfra-G has commissioned the FGD Plant at DTPS in FY 2007-08. The Commission, in its Orders while determining the tariff of DTPS for FY 2007-08 and FY 2008-09 has approved the auxiliary consumption for FGD separately in addition to normative auxiliary consumption applicable for the station. It is proposed to continue with the same methodology of separately approving the auxiliary consumption for FGD plant over and above the normative auxiliary consumption for the station till the actual performance data for at least 2-3 years is available in this regard.

MSPGCL

The average auxiliary consumption for most of the generating stations of MSPGCL for the last four years (i.e., FY 2004-05 to FY 2007-08) has been higher than the normative value of auxiliary energy consumption specified by the Commission for the first Control Period (except Uran and Chandrapur plant).

However, as discussed previously, the auxiliary consumption norm for existing stations of MSPGCL is to be proposed based on the outcome of the study being carried out by CPRI.

4.1.6.3 Secondary Fuel Consumption

The norms for secondary fuel consumption specified in the MERC Tariff Regulations, 2005 are as under:

a) ***Coal Based generating stations***

During Stabilization period	*Subsequent period*
4.5 ml/kWh	*2.0 ml/kWh*

b) ***Lignite- fired generating stations***

During Stabilization period	*Subsequent period*
5.0 ml/kWh	*2.5 ml/kWh*

The existing norms specified by the Commission are relaxed norms as compared to the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 for coal based generating stations (1 ml/kWh), while it is at par in the matter of lignite based generating stations. It is proposed to retain the above norms for secondary oil consumption for the existing Stations in the second Control Period also.

It is proposed to retain the above Secondary Fuel Consumption norms for the Stations that have declared commercial operation after the date of effectiveness of the MERC Tariff Regulations, 2005 and before the date of effectiveness of the MERC MYT Regulations.

As discussed earlier, ABPS Infra has considered benchmarking as a basis for setting the norms for secondary fuel oil consumption for the Generating Stations in the State of Maharashtra. The following Table shows the past performance of the Thermal generating stations of TPC-G, RInfra-G and MSPGCL in the context to secondary fuel oil consumption:

Table: Secondary fuel oil consumption (ml/kWh)

[redacted]

Note: *No secondary fuel oil consumption norm has been specified for TPC-G Units*

TPC-G

The generating Units of TPC-G have the capability to fire multiple fuels, whereas most of the other generating stations in the State of Maharashtra and other States do not have the capability to fire multiple fuels. Therefore, the comparison of TPC-G's generation stations with other generating stations would not be appropriate. More importantly, TPC-G fires liquid fuels as primary fuel also, and hence, it is not possible to distinguish between primary fuel and secondary fuel oil consumption. Consequently, TPC-G has never sought approval for secondary fuel oil consumption, and therefore, the Commission in the past has not stipulated any norm for secondary fuel oil consumption for TPC-G. Accordingly, it is suggested that no specific secondary fuel oil consumption norm may be stipulated for existing generating Units of TPC-G.

RInfra-G

As may be observed from the above Table, the average Secondary Fuel Oil consumption for the last four years (i.e., FY 2004-05 to FY 2007-08) is in the range of 0.12 to 0.18 ml/kWh, which is substantially lower than the Secondary Fuel Oil consumption norm of 2 ml/kWh as specified by the Commission for the first Control Period. In accordance with the MERC Tariff Regulations, RInfra-G has been allowed to retain its share of the efficiency gains due to the better than normative secondary fuel oil consumption achieved by DPTS, over the first Control Period.

Since, RInfra-G has operated at a very high Plant Load Factor (PLF) for several years, ABPS Infra has compared RInfra-G's Secondary Fuel Oil consumption with that of other high performing generating stations as shown in the Table below:

Table: Comparison of Secondary fuel oil consumption (ml/kWh)

[redacted]

**Source: CEA Report on Recommendations on operating norms of thermal power stations for the tariff period beginning April 1, 2009.*

The Secondary Fuel Oil consumption of DTPS is lower than that of other generating stations having high PLF. Thus, considering the actual operating data of RInfra-G, it is proposed to specify the secondary fuel oil consumption norm for DTPS as 0.14 ml/kWh with the objective of retaining some incentive for the Utility for improved performance.

MSPGCL

The average secondary fuel oil consumption for most of the generating stations of MSPGCL for the last four years (i.e., FY 2004-05 to FY 2007-08) has been higher than the normative secondary fuel oil consumption specified by the Commission for the first Control Period (except Khaperkheda and Chandrapur plant).

However, as discussed earlier, the secondary fuel oil consumption norm for existing stations of MSPGCL are to be approved after considering the outcome of the study being carried out by CPRI.

4.1.6.4 Transit losses

Transit and handling losses are very common in fuel transportation, especially for coal transportation. These losses happen mainly due to theft, leakage, weight reduction due to moisture evaporation, improper stacking, etc., and the losses are higher in load centre based generating stations as compared to that in pit head stations. The norms specified in MERC Tariff Regulations are as under:

"(a) Transit losses for coal based generating stations, as a percentage of quantity of coal dispatched by the coal supply company during the month shall be as given below:

i. *Pit head generating stations - 0.3%*
ii. *Non-pit head generating stations - 0.8%"*

The transit loss norms approved by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 are as under:

i. *"Pit head generating stations - 0.2%*
ii. *Non-pit head generating stations - 0.8%"*

It is evident from the above that the existing transit loss norms specified by the Commission are higher than the norms specified by the CERC.

The following Table shows the transit losses approved by the Commission and transit losses actually recorded by RInfra-G and MSPGCL over the period from FY 2004-05 to FY 2007-08. However, no transit losses are applicable in case of TPC-G stations, as TPC-G has not accounted for any transit losses, as the entire coal requirement is met through procurement of imported coal.

Table: Transit Losses (%)

[redacted]

As observed from the above Table, MSPGCL has managed to reduce the transit losses to 0.01 to 0.42% for its various Stations. MSPGCL, in its Annual Performance Review Petition for FY 2008-09, submitted that it has made full efforts to have correct weighing at colliery end and also at power station end, and undertaken follow up with Coal Companies, Railways and Railway Police Force for reducing theft during transport, which has resulted in considerable reduction in transit loss.

It is suggested that the transit loss norms may be specified as per CERC (Terms and Conditions of Tariff) Regulations, 2009 as under:

Transit losses for coal based generating stations, as a percentage of quantity of coal dispatched by the coal supply company during the month shall be as given below:

iii. Pit head generating stations - 0.2%
iv. Non-pit head generating stations - 0.8%

The above norms may be made applicable for all types of indigenous coal including washed coal.

Further, it may be noted that RInfra-G also reports transit loss on imported coal, whereas TPC-G as well as MSPGCL have never reported any such losses on imported coal. The Commission, in its latest APR Order for RInfra-G, has disallowed transit losses on imported coal and directed RInfra-G to procure imported coal on delivery basis.

4.1.7 Norms for Generating Stations commissioned/to be commissioned after the date of effectiveness of MERC Tariff Regulations, 2005 and before the date of effectiveness of MERC MYT Regulations

For new stations commissioned and expected to be commissioned before the date of effectiveness of the MERC MYT Regulations, the performance norms may be considered based on norms specified in the existing MERC Tariff Regulations.

4.1.8 Operation & Maintenance (O&M) Expenses

The O&M expenses comprise Employee Expenses, R&M Expenses and A&G expenses, and all three together constitute a significant part of the Aggregate Revenue Requirement of any power sector Utility.

In terms of developing the framework for the components of O&M expenses, the various Regulatory Commissions have adopted different approaches after duly considering the State specific requirements. The Regulatory Commissions have mainly adopted the following two approaches:

- Actual O&M expenses in the previous year with certain escalation factor for ensuing years
- O&M expenses based on certain performance benchmarks

In the traditional approach, the Commission has specified the O&M expenses based on the actual expenditure incurred during the previous year escalated using certain escalation factors for projecting the ensuing years' O&M expenses. Before deciding on the approach for O&M expenses, it is important to analyse the components of O&M expenses.

a. Employee Expense

Employee expenses include salaries, allowances payable to employees, wage arrears, terminal benefits, etc. Employee expense varies every year due to salary increase, promotion of employees and due to retirement/addition of employees. The increase in salary expenses would be expected to be such that it offsets the effect of inflation. One such indicator denoting the inflation is Consumer Price Index (CPI), reflecting the increase in price of consumer goods.

b. A&G Expenses

Administrative & General (A&G) expenses comprise expenses on office administration, rentals, travel, communication, telecommunication and other overheads, etc. The general indicators reflecting the variation in cost of general commodities are the Wholesale Price Index (WPI) and Consumer Price Index (CPI).

c. Repair & Maintenance (R&M) Expense

R&M, in terms of scheduled and break-down maintenance, is a part of any running business. Suitable provision for R&M expenses needs to be provided for smooth operation of generating stations. R&M expenses generally increase with the vintage of the plant. In initial years of operation, R&M cost is low due to new components, which increases with the increase in plant life. For escalation of R&M expenses, the WPI can be an indicator reflecting the increase in the cost of machinery and machine tools.

After going through each component of O&M expense, the issue is whether the Commission should detail the normative parameters and escalation factors for each of the expense heads or provide a normative framework for consolidated O&M expenses.

The existing MERC Tariff Regulations specify the normative O&M expenses to be computed in the following manner:

> *"34.6 Operation and Maintenance Expenses*
>
> *34.6.1 Existing generating stations*
>
> *(a) The operation and maintenance expenses including insurance shall be derived on the basis of the average of the actual operation and maintenance expenses for the five (5) years ending March 31, 2004, based on the audited financial statements, excluding abnormal operation and maintenance expenses, if any, subject to prudence check by the Commission.*
>
> *(b) The average of such operation and maintenance expenses shall be considered as operation and maintenance expenses for the financial year ended March 31, 2002 and shall be escalated at the rate of 4 per cent per annum to arrive at operation and maintenance expenses for the base year commencing April 1, 2005.*
>
> *(c) The base operation and maintenance expenses for each subsequent year shall be escalated at the rate of 4 per cent per annum to arrive at permissible operation and maintenance expenses for such financial year.*
>
> *Provided that in case, an existing generating station has been in operation for less than five (5) years as at April 1, 2004, the average shall be computed for such shorter period for which such generating station was in operation and such average shall be treated as*

the operating and maintenance expense for the base year commencing April 1, 2004. The operation and maintenance expenses for any subsequent financial year shall be computed in accordance with clause (c) above.

34.6.2 New generating stations
(a) Thermal generating stations
(i) Coal-based generating stations
200/210/250 MW sets : Rs. 10.82 lakh/MW
500 MW and above sets : Rs. 9.73 lakh/MW
Note:
For the generating stations having combination of 200/210/250 MW sets and 500 MW and above set, the weighted average value for operation and maintenance expenses shall be adopted.

(ii) Gas Turbine/Combined Cycle generating stations other than small gas turbine power generating stations
With warranty spares of 10 years : Rs. 5.41 lakh/MW
Without warranty spares : Rs. 8.11 lakh/MW

(iii) Small gas turbine power generating stations: Rs. 9.84 lakh/MW

(iv) Lignite-fired generating stations : Rs. 10.82 lakh/MW
The above operation and maintenance expense norms are for the base year commencing April 1, 2005, which shall be escalated at the rate of 4 per cent per annum to arrive at permissible operation and maintenance expenses for the relevant year of tariff period."

The CERC while setting the framework for determination of tariff for Thermal and Hydro generating stations under CERC (Terms and Condition for Tariff determination) Regulations, 2009 has provided norms for overall O&M expenses.

It is also essential to analyse the actual O&M expenses of the existing generating stations in Maharashtra. The following table shows the O&M expenses for TPC-G, RInfra-G and MSPGCL stations:

Table: Actual O&M expenses (Rs. Lakh/MW)

Generating company	Station	Unit	Capacity	Actual O&M Expenses/MW		
				2005-06	2006-07	2007-08
TPC-G	Trombay	Unit 4	150		12.89	12.67
		Unit 5	500		17.51	19.00
		Unit 6	500		12.72	18.40
		Unit 7	180		16.18	17.78
RInfra-G	Dahanu		500	12.49	12.478	15.50
MSPGCL	Khaparkheda		840	9.11	10.75	11.42
	Paras		58	31.53	32.11	41.69
	Bhusawal		478	15.02	15.51	16.74
	Nasik		910	12.42	12.77	15.93
	Parli		690	12.72	14.96	15.36
	Koradi		1080	12.42	13.90	13.55
	Chandrapur		2340	8.04	9.06	9.84
	Uran Gas		852	3.06	4.85	9.40

It may be observed from the above Table that the O&M expenses have increased over the years. Further, the O&M expenses of smaller unit stations in Rs Lakh/MW terms is much higher as compared to large unit size thermal stations. The O&M expenses for thermal stations also depends upon vintage of stations and hence the O&M expenses of older vintage stations are higher as compared to new stations.

ABPS Infra is of the view that it would be appropriate to fix the norms for O&M expenses on consolidated basis instead of specifying the norms for individual components of O&M expenses as it will give flexibility to the Utility to manage its expenditure.

CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has stipulated as under:

> *"(a) Coal based and lignite fired (including those based on CFBC technology) generating stations, other than the generating stations referred to in clauses (b) and (d):*

(Rs. in lakh/MW)

Year	200/210/250 MW sets	300/330/350 MW sets	500 MW sets	600 MW and above sets
2009-10	18.20	16.00	13.00	11.70
2010-11	19.24	16.92	13.74	12.37
2011-12	20.34	17.88	14.53	13.08
2012-13	21.51	18.91	15.36	13.82
2013-14	22.74	19.99	16.24	14.62

Provided that the above norms shall be multiplied by the following factors for additional units in respective unit sizes for the units whose COD occurs on or after 1.4.2009 in the same station:

200/210/250	
MW Additional 5th & 6th units	*0.9*
Additional 7th & more units	*0.85*
300/330/350 MW	
Additional 4th & 5th units	*0.9*
Additional 6th & more units	*0.85*
500 MW and above	
Additional 3rd & 4th units	*0.9*
Additional 5th & above units	*0.85*

(c) Open Cycle Gas Turbine/Combined Cycle generating stations

(Rs. in lakh/MW)

Year (1)	Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations (2)	Small gas turbine power generating stations (3)	Agartala GPS (4)
2009-10	14.80	22.90	31.75
2010-11	15.65	24.21	33.57
2011-12	16.54	25.59	35.49
2012-13	17.49	27.06	37.52
2013-14	18.49	28.61	39.66

(e) *In case of coal-based or lignite-fired thermal generating station a separate compensation allowance unit-wise shall be admissible to meet expenses on new assets of capital nature including in the nature of minor assets, in the following manner from the year following the year of completion of 10, 15, or 20 years of useful life:*

Years of operation Compensation Allowance (Rs lakh/MW/year)

0-10	*Nil*
11-15	*0.15*
16-20	*0.35*
21-25	*0.65"*

For new stations to be commissioned after the date of effectiveness of MERC MYT Regulations, it is proposed to specify the norms of O&M expense as specified in CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009.

For existing stations, which have been commissioned before the date of effectiveness of the MERC Tariff Regulations, 2005 the principles for determination of O&M norms are proposed as under:

a) The O&M expense norms for the Control Period will be derived on the basis of the average of the actual O&M expenses for the five (5) years ending March 31, 2009, based on the audited financial statements, excluding abnormal O&M expenses, if any, subject to prudence check by the Commission.
b) The average of such O&M expenses will be considered as the expenses for the financial year ended March 31, 2007, which will be escalated based on the escalation factor to be determined based on the CPI and WPI over the last three years, to arrive at O&M expenses for the base year commencing April 1, 2010.
c) The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above for FY 2009-10, at the escalation factor to be determined based on the CPI and WPI as mentioned above to arrive at permissible O&M expenses for each year of the Control Period.

For new stations commissioned and expected to be commissioned before the date of effectiveness of the MERC MYT Regulations, the O&M expenses may be considered based on norms specified in the existing MERC Tariff Regulations, which shall be escalated at the escalation factor to be determined based on the CPI and WPI that the Commission would compute to arrive at permissible O&M expenses for each year of the Control Period.

4.1.9 Other Income

The existing MERC Tariff Regulations does not specifically specify the treatment of other income for generating companies, i.e., income other than income from sale of electricity. However, the Commission has been deducting the income from other sources, while determining the tariff for the generating companies in the State of Maharashtra.

As regards the other income for generation business, MSPGCL had appealed against the Commission's Orders in Case No. 48 of 2005 and Case No. 68 of 2006. Para 73 of the ATE Judgment in Appeal No. 86 and 87 of 2007 stipulates as under:

> *"However, if the income can not be reasonably linked to any cost item allowed by the Commission as part of the ARR, the same should not be adjusted against the ARR of the Appellant, in the absence of specific Regulations."*

The Generating Companies can earn Other Income through sale of ash generated from coal based generating stations, sale of scrap, rent received from part of land given on lease, interest income on investments, etc. Therefore, any income earned by Generating Company can be categorised as income either from the assets or activities, for which all the expenses have been allowed to be recovered from the tariffs. Since all the legitimate costs are allowed to be recovered through tariffs, it is important that the income earned by Generating Companies other than income from sale of power should be considered and adjusted from Fixed (Capacity) charges as otherwise it will lead to additional profit to Generating Company in excess of permissible return. However, while considering the other income, the income corresponding to interest on investment made out of permissible Return on Equity should not be considered as other Income.

4.1.10 Incentive Mechanism

Introduction of incentive mechanism has shown a positive impact resulting in the increase in electricity generation from the same generating stations. An appropriate incentive mechanism should be designed after taking into consideration the merits and demerits of various alternatives and the long-term benefit to the sector. For incentive purpose, the following three approaches can be considered:

- Additional Return on Equity or Return on Capital Employed linked with increase in target PLF
- Paise/unit linked to scheduled generation beyond normative PLF
- Availability based incentive linked to Annual Fixed Charge

In case incentive is provided in terms of additional Return on Equity (RoE) or Return on Capital Employed (RoCE) linked with increase in target PLF, the incentive will vary for each Generating Station based on capital cost and means of finance (in case of RoE approach) of the Generating Station. The question arises as to why the incentive should vary for generating stations based on Project Cost and funding pattern. Further, this approach will also conversely provide more incentive to generating stations with higher capital cost.

Incentive in terms of paise/kWh beyond the normative PLF has been a mechanism widely adopted by the various Regulatory Commissions due to simplicity in implementation, and the fact that it ensures uniform incentive to all generating stations.

CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has specified the availability based incentive scheme for the thermal generating stations. For coal based stations, CERC has kept the target availability for payment of incentive same as the target availability for recovery of full fixed charges.

The existing MERC Tariff Regulations provides for incentive mechanism linked to the scheduled generation in excess of target PLF.

ABPS Infra has analysed the availability and PLF for various generating stations in the State of Maharashtra for the period from FY 2004-05 to FY 2007-08 as shown in the Table below:

Table: Availability and Plant Load Factor (%)

[redacted]

A generator should be incentivised for actual generation rather than availability to generate, as for distribution licensees, the actual generation has the utmost importance. Moreover, the generator is allowed to recover the fixed cost, if it achieves the target availability. Further, the approach to link the incentive to the AFC on some proportion will also conversely provide more incentive to generating stations with higher AFC.

In view of above, ABPS Infra proposes to continue with the existing incentive mechanism as stipulated under the MERC Tariff Regulations and therefore, the incentive mechanism should be linked with target PLF based on actual generation. Accordingly, the Generating Company will be entitled for incentive at a flat rate of 25.0 paise/kWh for ex-bus actual energy generated in excess of Target Plant Load Factor.

However, since the proposed mechanism for incentive is linked to the actual generation, it is proposed to modify the definition of the Plant Load Factor as under:

"Plant Load Factor", for a given period, means the total sent-out energy corresponding to actual generation during such period, expressed as a percentage of sent out energy corresponding to installed capacity in that period and shall be computed in accordance with the following formula:

$$\text{Plant Load Factor (\%)} = 10000 \times \sum_{i=1}^{N} AG \; / \; \{ N \times IC \times (100 - AUXn) \} \; \%$$

where - N = number of time blocks in the given period

AG = Actual Generation in MW for the i^{th} time block in such period

IC = Installed Capacity of the generating station in MW

AUX = Normative Auxiliary Consumption in MW, expressed as a percentage of gross generation

4.1.11 Treatment of Infirm Power

The power generated prior to commercial operation of the Unit of a generating station is treated as infirm power. CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has linked the infirm power price with the Unscheduled Interchange (UI) rate under the Availability Based Tariff (ABT) mechanism. The stated objective behind this linkage was to increase the availability of power in the grid. However, pricing of infirm power linked to frequency is against the basic principle of determining the tariff on 'cost-plus' basis and it leads to artificially increasing the price, when the cost of generation may be far less than the prevailing UI rate. Also, linking the price with the frequency will only create uncertainty over the price of the power that the generating station would get for injection of power. Further, it should not result in a situation where the Generating Company delays the commissioning of the Plant, since the rate available for infirm power injection at UI rate may be more remunerative.

It is suggested that the price of infirm power from thermal generating stations may be fixed at variable cost to recover the fuel costs only. If the revenue from sale of infirm power is higher than the fuel cost, the recovery in excess of fuel cost needs to be adjusted from the capital cost. The pricing of infirm power at variable charge is a simple mechanism and will avoid complications in tariff determination. This will also ensure that the capital cost recovery in terms of Fixed (Capacity) charge is allowed after COD of the Generating Station.

4.1.12 Cost of Fuel and Calorific Value

For determining the variable charge component of tariff for thermal stations, the cost of fuel to be considered should be the landed cost of fuel. The landed cost of fuel should include price of fuel corresponding to the grade/quality/calorific value of fuel including royalty, taxes and duties as applicable, transportation, coal washing charges as applicable, and the normative transit losses.

While determining the tariff for ensuing years, it will be preferable to consider the landed cost of fuel and calorific value based on actual values for the most recent three to four months. The variation in landed price of fuel and calorific value of fuel may be allowed to be adjusted on quarterly basis through Fuel Adjustment Cost (FAC) mechanism.

4.1.13 Fuel Cost Adjustment (FAC) Charge

The Commission approves the fuel costs and energy charge for the generating companies based on certain fuel price assumptions. Fuel prices, especially of imported coal and oil, vary according to national and international market prices. Therefore, electricity generation cost varies in proportion to the increase in fuel cost. The variation in fuel price is an uncontrollable factor, and therefore, any variation in the fuel cost should be passed on to the consumers of the Generating Companies, i.e., Distribution Licensees.

Under the MERC Tariff Regulations, the Commission has specified the detailed mechanism for computation of FAC charge for distribution licensees only, however, for generating companies, the adjustment in fuel prices and calorific value is allowed on monthly basis. It is suggested that the Commission may specify specific the FAC charge mechanism and formats for Generating Companies as part of Regulations.

As regards the adjustment of rate of energy charge on account of variation in price and heat value of fuels, it is suggested that initially, Gross Calorific Value of coal/lignite or gas or liquid fuel or secondary fuel oil shall be taken as per actuals of the preceding three months. Any variation shall be adjusted on month to month basis on the basis of Gross Calorific Value of coal/lignite or gas or liquid fuel or secondary fuel oil received and burnt and landed cost incurred by the generating company for procurement of coal/lignite, oil, or gas or liquid fuel or secondary fuel oil, as the case may be based on the following formula:

FAC= A + B

A – Fuel Adjustment Cost for Secondary Fuel oil in Paise/kWh sent out
B – Fuel Adjustment Cost for Coal in Paise/kWh sent out

And,

$$A = \frac{10 \times (SFC_n)(P_{om}) - (P_{os})}{(100 - AC_n)}$$

$$B = \frac{10}{(100 - AC_n)} \Big[\{(SHR_n)(P_{cm}/K_{cm}) - (P_{cs}/K_{cs})\}$$

$$- (SFC_n)\{(k_{om} x P_{cm}/K_{cm}) - (k_{os} x P_{cs}/K_{cs})\} \Big]$$

Where,

SFC_n – Normative Specific Fuel Oil consumption in ml/kWh

SHR_n – Normative Gross Station Heat Rate in kcal/kWh

AC_n – Normative Auxiliary Consumption in percentage

P_{om} – Weighted Average price of fuel oil on as consumed basis during the month in Rs./KL.

K_{om} – Weighted average GCV of fuel oils for the month in kcal/Litre

P_{os} – Base value of price of fuel oils as taken for determination of base energy charge in Tariff Order in Rs./KL.

K_{os} – Base value of gross calorific value of fuel oils as taken for determination of base energy charge in tariff order in kcal/Litre

P_{cm} – Weighted average price of coal procured and burnt during the month at the power station in Rs./MT.

K_{cm} – Weighted average gross calorific value of coal fired at boiler front for the month in kcal/Kg

P_{cs} – Base value of price of coal as taken for determination of base energy charge in Tariff Order in Rs./MT

K_{cs} – Base value of gross calorific value of coal as taken for determination of base energy charge in tariff order in kcal/Kg

However, the generating companies should submit the computation to the Commission on quarterly basis for post-facto approval of Fuel Adjustment Charge.

4.2 *Hydro Generating Stations*

The total hydro capacity installed in the State is 3643 MW out of which, TPC-G has 447 MW of hydro generation capacity and the rest is constituted by hydel generating stations owned by GoM and operated and maintained by MSPGCL.

4.2.1 Capital Cost and Means of Finance

The capital cost in hydro generating stations includes the cost of dam, intake water system, turbines, generators and discharge water system. The critical issue with respect to capital cost of hydro projects is ascertainment of total capital cost of hydro project apportioned to power generation.

As discussed earlier, the current methodology of approval of capital cost based on actual capital expenditure subject to prudence check may be continued.

Under this mechanism, the Generating Company should file a separate Petition for approval of Tariff on Cost plus basis after achieving COD of the Project. While filing a Petition for approval of Tariff, the Generating Company should submit the estimated Project Cost, original schedule for the Project, actual completed Project Cost based on audited accounts and actual schedule for the Project along with reasons for cost over-run and delay, if applicable. Further, the Generating Company should also submit the details of total Capital Cost of the Project and Capital Cost apportioned to power generation activity along with the detailed rationale for the same. The cost over-run and delay in achieving COD of the Project needs to be considered on case to case basis based on justification provided by the Generating Company.

4.2.2 Components of Tariff and Recovery of Costs

The existing MERC Tariff Regulations stipulate two-part tariff for sale of electricity from a hydro power generating station comprising of Capacity Charges and Primary Energy Charges in the following manner:

(i) Annual Capacity Charges = Annual Fixed Charges - Energy Charge
Provided further that the Energy Charge shall not exceed the Annual Fixed Charge.

(ii) Annual Fixed Charges comprises the following elements:

a. Interest on Loan Capital
b. Depreciation including Advance Against Depreciation and amortisation of intangible assets
c. O&M Expenses
d. Return on Equity Capital
e. Interest on Working Capital
f. Taxes on Income

As regards rate of Energy Charges, MERC Tariff Regulations stipulates that the rate of energy for hydro stations shall be worked out on the basis of paise per kWh rate on ex-bus energy scheduled to be sent out from the hydro generating stations. The MERC Tariff Regulations further stipulate that recovery from Energy Charges shall not exceed the Annual Fixed Charges.

The present approach of two-part tariff for hydro stations as specified in the MERC Tariff Regulations is reasonable from the generation as well as distribution point of view. However, it is observed that the present MERC Tariff Regulations do not provide any incentive for generating more than the design energy. Accordingly, ABPS Infra proposes that some incentive should be provided for hydel generating stations generating energy more than the design energy.

Further, during the last 3 years, the Commission has been approving differential peak and non-peak generation and single-part tariff for the hydro Stations of MSPGCL and TPC-G to encourage the shift of hydel generation from non-peak to peak hours, in view of hydro resources being a scarce natural resource. At the same time, the Commission was also of the view that the tariff applicable to the consumers should not be increased. However, since the differential hydro pricing mechanism was resulting in over-recovery vis-à-vis actual revenue requirement of hydro stations, the Commission incorporated the concept of a hydro rebate to be passed through to the Distribution Licensees through the monthly bill, so that the total amount recoverable remains the same. Subsequently, MSPGCL submitted that the Generating Companies have no incentive to shift the generation from non-peak hours to peak hours, since the entire benefit is passed on to the consumers, and also because of the control over generation exercised by the State Load Despatch Centre and MSEDCL. As a consequence, the Commission introduced an incentive mechanism, whereby, 5% of the excess recovery is shared between the Generating Company and Distribution Licensee.

The month-wise comparison of hydel generation during peak and off peak hours for Koyna Hydel Station of MSPGCL for FY 2006-07 and FY 2007-08 is given in the following Table:

Table: Month-wise Hydel Generation of Koyna Station during Peak and Off-Peak hours (MU)

[redacted]

As observed from the above Table that peak hour generation for Koyna Complex has been in the range of 45% and there is no shift from off peak hour generation to peak hour generation.

The month-wise comparison of hydel generation during peak and off peak hours for generating stations of TPC-G for FY 2006-07 and FY 2007-08 is given in the following Table:

Table: Month-wise Hydel Generation of TPC-G hydel stations during Peak and Off-Peak hours (MU)

[redacted]

As observed from the above Table that peak hour generation for generating stations of TPC-G has increased from 42% in FY 2006-07 to 49% in FY 2007-08.

Based on the analysis of actual generation data of hydel stations during peak and non-peak hours, it is observed that the above-mentioned differential hydro generation tariff has not resulted in the desired shift in the generation from non-peak to peak hours. Further, in various proceedings, MSPGCL has submitted that it is not possible for them to shift the generation from non-peak hours to peak hours due to several reasons. Therefore, since no real benefit is being derived from the differential hydro tariff mechanism for peak and non-peak hours, it is suggested that the same may be discontinued, and the tariff may be determined in accordance with the methodology prescribed under the MYT Regulations.

As regards the computation of tariff for hydel generating stations, CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has stipulated as under:

> *"(2) The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be*
> *AFC x 0.5 x NDM / NDY x (PAFM / NAPAF) (in Rupees)*
> *Where,*
> *AFC = Annual fixed cost specified for the year, in Rupees.*
> *NAPAF = Normative plant availability factor in percentage*
> *NDM = Number of days in the month*
> *NDY = Number of days in the year*
> *PAFM = Plant availability factor achieved during the month, in Percentage*
> *(4) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary, excluding free energy, if any, during the calendar month, on ex power plant basis, at the computed energy charge rate. Total Energy charge payable to the generating company for a month shall be :*
>
> *(Energy charge rate in Rs. / kWh) x {Scheduled energy (ex-bus) for the month in kWh} x (100 – FEHS) / 100.*
>
> *(5) Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis, for a hydro generating station, shall be determined up to three decimal places based on the following formula, subject to the provisions of clause (7) :*

ECR = AFC x 0.5 x 10 / { DE x (100 – AUX) x (100 – FEHS)}

Where,

DE = Annual design energy specified for the hydro generating station, In MWh, subject to the provision in clause (6) below. FEHS = Free energy for home State, in per cent, as defined in regulation 32."

...

(7) In case the energy charge rate (ECR) for a hydro generating station, as computed in clause (5) above, exceeds eighty paise per kWh, and the actual saleable energy in a year exceeds { DE x (100 – AUX) x (100 – FEHS) / 10000 } MWh, the Energy charge for the energy in excess of the above shall be billed at eighty paise per kWh only:

Provided that in a year following a year in which total energy generated was less than the design energy for reasons beyond the control of the generating company, the energy charge rate shall be reduced to eighty paise per kWh after the energy charge shortfall of the previous year has been made up."

CERC (Terms and Conditions of Tariff) Regulations, 2009 allows recovery of 50% of fixed costs through the capacity charge and 50% of the fixed costs through the energy charge corresponding to design energy. Further, the mechanism stipulated by CERC also provides for incentive towards generation in excess of the design energy.

In view of the above, it is proposed that the tariff mechanism for hydro stations may be specified as stipulated in the CERC (Terms and Conditions of Tariff) Regulations, 2009.

4.2.3 Norms of Operation

Normative Capacity Index for Recovery of Annual fixed Charges

The normative capacity index as specified by the Commission in the existing MERC Tariff Regulations for hydro generating stations are as under:

Particulars	First Year of Commercial Operation	After First year of Commercial Operation
Purely Run-of-river power station without pondage	85%	90%
Storage type and Run-of-river power stations with pondage	80%	85%

As it is proposed to adopt the tariff mechanism specified in CERC (Terms and Conditions of Tariff) Regulations, 2009, it will be preferable to specify the norms of operation as stipulated in CERC (Terms and Conditions of Tariff) Regulations, 2009. For new generating stations to be commissioned after the date of effectiveness of the MERC MYT Regulations, the Normative Plant Availability Factor (NAPAF) may be specified in accordance with the norms specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 as under:

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

Note:

A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.

For existing stations, it is proposed that the NAPAF may be specified in the MYT Order after considering the past performance and based on methodology stipulated in CERC (Terms and Conditions of Tariff) Regulations, 2009.

Auxiliary Energy Consumption

The auxiliary energy consumption as specified by the Commission in its existing MERC Tariff Regulations for hydro generating stations are as under:

(a) Surface hydro electric power generating stations with rotating exciters mounted on the generation shaft – 0.2% of energy generated

(b) Surface hydro electric power generating stations with static excitation system - 0.5% of energy generated

(c) Underground hydro electric power generating stations with rotating exciters mounted on the generator shaft - 0.4% of energy generated

(d) Underground hydro electric power generating stations with static excitation system - 0.7% of energy generated

The existing MERC Tariff Regulations stipulates transformation losses of 0.5% from generation voltage to transmission voltage.

It is suggested that the auxiliary consumption norm may be specified (which includes transformation losses also) as specified by CERC in its CERC (Terms and Conditions of Tariff) Regulations, 2009 for various types of stations, as follows:

(a) Surface hydro generating stations

i. With rotating exciters mounted on the generator shaft: 0.7%

ii. With static excitation system: 1%

(b) Underground hydro generating stations

i. With rotating exciters mounted on the generator shaft: 0.9%

ii. With static excitation system: 1.2%

4.2.4 Operation and Maintenance Expenses

CERC, in its CERC (Terms and Conditions of Tariff) Regulations, 2009 has stipulated as under:

"(f) Hydro generating station

(i) Operation and maintenance expenses, for the existing generating stations which have been in operation for 5 years or more in the base year of 2007-08, shall be derived on the basis of actual operation and maintenance expenses for the years 2003-04 to 2007-08, based on the audited balance sheets, excluding abnormal operation and maintenance expenses, if any, after prudence check by the Commission.

(ii) The normalised operation and maintenance expenses after prudence check, for the years 2003-04 to 2007-08, shall be escalated at the rate of 5.17% to arrive at the normalized operation and maintenance expenses at the 2007-08 price level respectively and then averaged to arrive at normalized average operation and maintenance expenses for the 2003-04 to 2007-08 at 2007-08 price level. The average normalized operation and maintenance expenses at 2007-08 price level shall be escalated at the rate of 5.72% to arrive at the operation and maintenance expenses for year 2009-10:

Provided that operation and maintenance expenses for the year 2009-10 shall be further rationalized considering 50% increase in employee cost on account of pay revision of the employees of the Public Sector Undertakings to arrive at the permissible operation and maintenance expenses for the year 2009- 10.

(iii) The operation and maintenance expenses for the year 2009-10 shall be escalated further at the rate of 5.72% per annum to arrive at permissible operation and maintenance expenses for the subsequent years of the tariff period.

(iv) In case of the hydro generating stations, which have not been in commercial operation for a period of five years as on 1.4.2009, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation & resettlement works). Further, in such case, operation and maintenance expenses in first year of commercial operation shall be escalated @5.17% per annum up to the year 2007-08 and then averaged to arrive at the O&M expenses at 2007-08 price level. It shall be thereafter escalated @ 5.72% per annum to arrive at operation and maintenance expenses in respective year of the tariff period.

(v) In case of the hydro generating stations declared under commercial operation on or after 1.4.2009, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation & resettlement works) and shall be subject to annual escalation of 5.72% per annum for the subsequent years."

For existing stations, it is suggested that the norm for O&M expenses may be specified based on actual O&M expenses during the last five years. The principles for determination of O&M norms are proposed as under:

a) The normative O&M expenses for the second Control Period will be derived on the basis of the average of the actual O&M expenses for the five (5) years ending March 31, 2009, based on the audited financial statements, excluding abnormal O&M expenses, if any, subject to prudence check by the Commission.
b) The average of such O&M expenses will be considered as the expenses for the financial year ended March 31, 2007, which will be escalated based on the escalation factor to be determined based on the CPI and WPI over the past three years, to arrive at O&M expenses for the base year commencing April 1, 2010.

In case of the hydro generating stations, which have not been in commercial operation for a period of five years as on 31.3.2009, operation and maintenance expenses may be fixed at 2% of the original project cost (excluding cost of rehabilitation and resettlement works) for first year of operation, which may be escalated based on the escalation factor to be determined based on the CPI and WPI to arrive at O&M expenses for the base year commencing April 1, 2010.

Similarly, for new stations, the norms for O&M expenses for first year of operation may be specified as 2% of the original project cost (excluding cost of rehabilitation and resettlement works) for the first year of operation.

The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above for FY 2009-10, at the escalation factor to be determined based on the CPI and WPI to arrive at permissible O&M expenses for each year of the Control Period.

4.2.5 Treatment of Infirm Power

There are two alternative approaches for treatment of infirm power from hydro generating stations:

- Rate of Infirm Power equivalent to Primary Energy Rate
- Supply of Infirm Power free of charge

In case of hydro generating stations, there is no question of fuel cost, and recovery from primary energy rate is intended for part recovery of Annual Fixed Costs. Hence, under Option 1, the revenue earned from sale of infirm power needs to be deducted from the Capital Cost.

The other alternative in case of hydro power generating stations is that the infirm power may be supplied free of cost as there are no fuel costs involved. However, since as a basic principle, any power supplied to the Distribution Licensee should not be free of charge, it is proposed to adopt Option 1 for treatment of infirm power in case of hydro generating stations.

5 Norms and Principles for determination of Revenue Requirement and Transmission Tariff

5.1 Historical Background of Transmission Pricing within Maharashtra during Last Control Period (FY08 to FY10)

5.1.1 Brief Status prior to Composite Intra-State Transmission System

Historically in Maharashtra, the transmission lines, sub-stations and transmission network thereof, have been developed over the period by different licensees such as Maharashtra State Electricity Transmission Co. Ltd (MSETCL which is a successor entity of MSEB), The Tata Power Company Ltd (TPC) and Reliance Infrastructure Ltd (RInfra – formerly known as REL). The intra-State transmission network within Maharashtra has been designed and developed for efficient evacuation of intra-State generation to meet the load requirement of various distribution licensees and other transmission system users.

Prior to enactment of Electricity Act 2003 (EA 2003) and even for a considerable time later, most of these licensees had integrated operations and continued to own distribution business and generation assets in addition to the transmission assets. However, pursuant to enactment of EA 2003, 'transmission' has to be viewed as a distinct licensed activity to be regulated in accordance with the provisions of the EA 2003. Further, for determination and allocation of transmission cost to various users, a separate accounting for the transmission function of the Utility must be in place. Accordingly, the Commission had directed all licensees to undertake 'functionwise' segregation of the assets and liabilities and furnish their Petitions for Annual Revenue Requirement for each function separately.

In addition, it may be noted that pursuant to enactment of EA 2003, GOM has notified MSETCL to act as State Transmission Utility (STU) vide its GR no. Reform 1004/S.No 8885/Energy-5 dated 17th February 2005 in accordance with the provisions Section 39 of EA2003. As per provisions of Section 39(2), MSETCL, as STU, is responsible to undertake all activities related to transmission planning, co-ordination and ensuring development of an efficient, co-ordinated and economical system of intra-state transmission for smooth flow of electricity from generating stations to the load centers, within State.

Currently, TPC-T and RInfra-T (formerly REL-T) undertakes the transmission function for TPC and RInfra respectively. The transmission assets (lines and sub-stations) owned and operated by TPC and RInfra are catering only to the requirement of their 'distribution business' in their respective distribution license area. In case of RInfra, its 220kV transmissions assets (lines and substations) had been developed, mainly for evacuation of power from its generating station located at Dahanu. However, in future, utilization of these assets by EHV/HV consumers located in their licensed area or by generators or by other licensees in accordance with the provisions of Transmission Open Access Regulations cannot be ignored and should be encouraged.

Thus, there exist multiple transmission licensees in the State which constitutes the **Intra-State transmission system (InSTS)**. However, parity in transmission pricing across the State was required for the following reasons.

- Enabling non-discriminatory open access for all InSTS Users (generators, other licensees and OA consumers) irrespective of their entry point /exit point and distribution licensee to which such OA Users belong.
- Encouragement for free flow of power over 'intra-State transmission system'
- Uniformity and parity amongst the consumers eligible for OA (EHV/HV) of different licensees.
- To develop a transmission pricing mechanism in line with the provisions of notified National Electricity Policy (NEP) and Tariff Policy (TP).

In order to meet above requirements, the Commission had framed a **Transmission Pricing framework for Intra-State Transmission System** after considering the stakeholders views and issued an Order dated June 27, 2006. The salient features of the same are discussed in the subsequent section.

5.1.2 Salient features of Transmission Pricing Order (27-Jun-06)

In exercise of its powers vested as per provisions of the EA03, the Commission passed the Order on "Development of Transmission Pricing Framework for the State of Maharashtra" on June 27, 2006. The Order covered the 'Transmission Pricing

Framework' for Maharashtra and elaborated on various features of the Transmission Pricing framework after considering the views of various stake holders.

The salient features of the arrangement for "Transmission Pricing of Intra-State Transmission System" as specified in the Order are as under.

- Intra-State transmission system shall comprise composite transmission network of MSETCL, TPC, REL and any other transmission licensee, in future.
- Each transmission licensee including existing transmission licensees (i.e. MSETCL, TPC and REL) shall submit its ARR Petition to the Commission in accordance with the MERC (Terms and conditions of Tariff) Regulations, 2005 and seek its approval thereof.
- Aggregate of Annual Revenue Requirement of all licensees, as approved by the Commission, shall form "Pooled Cost" (or termed as "Total Transmission System Cost – TTSC) of the intra-State transmission system, to be recovered from the Transmission System Users (TSUs).
- The 'Base Transmission Capacity Rights' for 'capacity utilisation' shall be denominated in terms of 'kW'. The TTSC shall be shared amongst the TSUs based on the 'contribution to co-incident peak demand' (CPD) by each TSU. However, for FY2006-07, until adequate metering arrangement is put in place, transmission tariff shall be based on share of 'peak demand' of concerned TSU during each month of the previous year. For this purpose, average of such 12-monthly contributions to peak demand by each TSU shall form basis for arriving at 'Base TCR' and overall share/contribution of each TSU thereof.
- Accordingly, 'Base Transmission Tariff' for each financial year shall be derived as 'TTSC' of intra-State transmission system divided by 'Base Transmission Capacity Rights' and denominated in terms of "Rs/kW/month" or "Rs/MW/day" or "Rs/kWh".
- The Transmission Tariff has been designed such that recovery of revenue requirement of transmission licensees is achieved by way of "composite charge" for use of intra-State transmission system.
- Further, the Transmission Tariff has been designed such that recovery of revenue requirement of transmission licensees is achieved only through drawal of energy, i.e., all off-takers (licensee, open access users) shall bear the transmission tariff.

The generating companies should be charged for injection of energy only if they seek open access for sale to consumers/licensees outside the State.

- Postage Stamp Method of recovery is most suitable for design of transmission tariff at this stage and the size of postage stamp should be the same for the entire State and denominated in terms of Rs/MW/month or Rs/kW/day.
- There shall be charges for drawal/injection of reactive energy linked to nominal voltage.
- Transmission loss shall be borne by all TSUs (off-takers) on pro-rata basis based on their energy drawal depending on actual transmission loss level. Any variation in the actual transmission loss level from the normative transmission loss level, if any, set by the Commission shall be adjusted in accordance with the provisions contained under MERC (Terms and Conditions for Tariff) Regulations 2005.
- There shall be incentive mechanism in place linked to target availability of the transmission lines.
- MSETCL, as Government Company operating the SLDC, shall be responsible for undertaking recording of State-wide energy accounts, monitoring of power flows and recording of utilization of capacity across intra-State transmission system.
- Each TSU (distribution licensee or Transmission OA User), shall be required to pay intra-State transmission system charges (InSTS charges) at the approved rate of "Base Transmission Tariff" corresponding to its utilization of 'intra-State transmission' capacity.
- The Proposed Arrangement for 'Transmission Pricing' is scalable in the sense that, as the system of metering, energy accounting and billing evolves, and power flows across intra-State transmission system can be monitored more accurately from instant to instant, the 'Base Transmission Capacity Rights' can be modified to adopt 'MW-mile' method for charging the 'Transmission Tariff'.
- Besides, future addition to transmission capacity (in accordance with the approved Transmission Plan) within the State can be undertaken by STU or existing other transmission licensee or any other new transmission licensee. The ARR pertaining to such transmission capacity addition shall form part of overall 'TTSC' of intra-State transmission system.

- The competitive bidding guidelines for procurement of transmission capacity additions can be easily adopted for future capacity addition programme without modification to 'Transmission Tariff' framework.
- SLDC shall continue to undertake State-wide energy accounting and determination of transmission losses for intra-State transmission system.
- The said Transmission Pricing Framework Order shall be applicable to both, long term and short term open access users and will be effective from the date of issue of this Order and shall be operative for the fiscal year 2006-07.

5.1.3 Merits/Demerits of Existing Transmission Pricing framework

'Composite Transmission Charge' methodology for pricing the utilization of 'intra-State transmission system' within Maharashtra has the following merits.

- It avoids the problem of pan-caking of 'licensee specific transmission charges' and treats all OA transactions of TSUs on par irrespective of their drawal/injection point and licensee to which such consumer belongs.
- Under this methodology, there is no need to review or track physical transactions.
- Under integrated network environment, augmentation and network expansion benefits all. Thus, composite transmission charge methodology for InSTS recognizes need for socializing such costs.
- Thus, transmission planning and network expansion can take place without any bias or any other considerations, by keeping in view 'free flow power across' InSTS as primary motive.
- This will encourage multiple OA transactions to take place, thereby inducing competition.
- The 'Composite Transmission charge' methodology is in line with MERC's Open Access regulations in the sense that it strives to treat all open access transactions of consumers connected to InSTS on par, irrespective of location of consumer or the licensee to which it belongs.

However, the methodology has the following demerits too.

- The existing pricing methodology is insensitive to distance, and it does not recognize the direction and quantum of power flow thereby signals to encourage efficient use of transmission network are weak under current framework.
- NEP and TP mandates that the national tariff framework implemented should be sensitive to distance, direction and related to quantum of flow. However, the current methodology does not show these characteristics. However, NEP and TP envisage that such framework would be first developed by Central Electricity Regulatory Commission (CERC) for regional transmission system and the same could be adopted at State level after two years of its introduction at regional level. Such framework is under development at regional level by CERC.

5.1.4 Salient features of Order dt. 13.11.2007 (Case 34 of 2007)

In order to fulfil the duties as vested under Section 39 (2)(c) of EA 2003, which stipulates the function of the STU as to ensure development of an efficient, co-ordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centres, MSETCL in its capacity as STU needs to Plan large capital expenditure schemes to ensure proper evacuation of the power generated by the upcoming generation stations in the Maharashtra and also undertake its execution in its capacity as transmission licensee. Besides, MSETCL will also have to strengthen the existing Transmission Infrastructure to transmit the said power efficiently to the load centres. Hence, MSETCL sought for an In-Principle approval to proceed with the steps required to be taken for the development of the transmission infrastructure facilities to facilitate the evacuation of the power in the State, including dedicated transmission lines and other associated facilities with the presumption that the expenses incurred on the same will be recoverable “In-Principle” through MSETCL’s ARR. However, MSETCL desired to seek certain clarifications in respect of roles and responsibilities of various entities including other transmission licensees and generating companies in development of transmission facilities within State and accordingly, it filed a Petition (Case 34 of 2007) before the Commission.

In response to the above, the Commission issued an Order dated November 13, 2007 on the above mentioned matter (Case 34 of 2007). The following issues were discussed in the Order.

- Whether 'evacuation arrangement' forms part of 'dedicated transmission line' or part of 'intra-State transmission system'?
- Who should develop transmission projects /evaluation arrangement and what is MSETCL's role in development of such projects?
- What is the procedure for approval of Investment Plan and can in-principle approval be sought for Investment Plan?
- Whether transmission/evacuation arrangement for generating stations of State generating company, independent power producers and merchant generator be treated uniformly?
- What should be the nature of commercial arrangement between transmission licensee and generating company?
- Whether MSETCL has freedom to incorporate suitable clauses/commercial conditions such as security requirements under the commercial arrangements with generating companies to safeguard its interests on case-to-case basis?

The Commission made the following rulings with regard to the above mentioned issues in the Order.

- The evacuation arrangement including transmission lines for generation projects of MSPGCL, private developers under the CBG route or otherwise, forms part of InSTS network. Being part of InSTS, the expenditure incurred for such transmission infrastructure shall form part of total transmission system cost of InSTS independent of who develops such transmission infrastructure. In case MSETCL undertakes to develop such evacuation infrastructure, the expenditure made by MSETCL shall form part of its ARR.
- Development of 'Transmission System Plan' is the statutory responsibility of the MSETCL in its capacity as STU and no approval of the Commission is necessary for the transmission system plan developed by STU in discharge of its statutory function. However, every transmission licensee is required to submit its 'Investment Plan', which is formulated in line with 'Transmission System Plan' for approval of the Commission.

- Transmission tariff shall be applicable to generators for injection of power to the extent of power wheeled outside the State and such recovery of transmission cost from Merchant Generators shall be adjusted against Total Transmission System Cost (TTSC) for InSTS to be recovered from Transmission System Users (TSU) within State.
- The licensees need to enter into appropriate commercial arrangements including Connection Agreement and Bulk Power Transmission Agreement.
- The Generating Company and transmission licensees need to devise appropriate commercial agreements such as Transmission Development Agreement in order to safeguard their respective interests.
- The Commission directed MSETCL, in its capacity as STU to develop such Model Development Agreement for Evacuation Scheme in consultation with the Grid Co-ordination Committee and submit the same to Commission for approval within one month from date of issuance of the said Order.

5.2 *Regulatory Framework and Recent Regulatory Developments*

5.2.1 Legal and Regulatory framework for Transmission

As per Section 40 of the EA 2003, the transmission licensee is obliged (a) to build, maintain and operate an efficient, co-ordinated and economical inter-State transmission system or intra-State transmission, as the case may be (b) to comply with directions of RLDCs and SLDCs as the case may be, and (c) to provide non-discriminatory open access to its transmission system for use by any licensee or generating company or any consumer as and when such open access is provided by State Commission on payment of the transmission charges. It is envisaged that Transmission Charges should be determined such that it facilitates open access transactions and encourages efficient use of the intra-State transmission system, while ensuring adequacy of revenue requirement for the transmission licensee.

5.2.1.1 Provisions under NEP and Tariff Policy

National Electricity Policy

The National Electricity Policy (NEP) notified by the Government of India (GoI) in February 2005, in accordance with provisions of Section 3 of the EA 2003, stipulates that the State Commission should determine the Transmission Charges by June 2005. Further, it advocates nationwide uniformity and consistency in Transmission Pricing in order to facilitate cost effective transmission of power across the country. Accordingly, it stipulates that transmission pricing, as far as possible, should be sensitive to distance, direction and related quantum of flow. The relevant extract of the NEP are as under:

"Non-discriminatory open access shall be provided to competing generators supplying power to licensees upon payment of transmission charge to be determined by the appropriate Commission. The appropriate Commissions shall establish such transmission charges no later than June 2005. ***(Cl 5.3.4)***

To facilitate cost effective transmission of power across the region, a national transmission tariff framework needs to be implemented by CERC. The tariff mechanism would be sensitive to distance, direction and related to quantum of flow. As far as possible, consistency needs to be maintained in transmission pricing framework in inter-State and intra-State systems. Further it should be ensured that the present network deficiencies do not result in unreasonable transmission loss compensation requirements." ***(Cl 5.3.5)***

Tariff Policy

The Tariff Policy notified by Ministry of Power (MoP), GoI on January 6, 2006 deals with several aspects pertaining to Transmission as under –

- Transmission Planning
- Transmission Pricing
- Infrastructure
- Approach for Transmission Loss
- Other issues in transmission

The Tariff Policy, in so far as transmission is concerned, seeks to achieve the following objectives:

1. Ensuring optimal development of the transmission network to promote efficient utilization of generation and transmission assets in the country;
2. Attracting the required investments in the transmission sector and providing adequate returns.

The relevant extracts of the Tariff Policy are as under:

Clause 7.1 Transmission Planning

"(2) The National Electricity Policy mandates that national tariff framework implemented should be sensitive to distance, direction and related to quantum of power flow. This would be developed by CERC taking into consideration the advice of the CEA. Such tariff mechanism should be implemented by 1st April 2006." (emphasis added)

Clause 7.1 Transmission Pricing

"(3) Transmission charges, under this framework, can be levied on MWper circuit kilometer basis, zonal postage stamp basis, or some other pragmatic variant, ***the ultimate objective being to get the transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system****. It is necessary that transmission tariff framework gives the right signals for siting of new generation and also ensures that merit order of generating stations does not get distorted. The overall tariff framework should be such as not to inhibit planned development/ augmentation of the transmission system, but should discourage non-optimal transmission investment. (emphasis added)*

(5) The ***Central Commission would establish, within a period of one year, norms*** *for capital and operating costs, operating standards and performance indicators for transmission lines at different voltage levels. Appropriate baseline studies may be commissioned to arrive at these norms.*

(6) Investment by transmission developer other than CTU/STU would be invited through competitive bids. ***The Central Government will issue guidelines in three months for bidding process for developing transmission capacities.*** *The tariff of the projects to be developed by CTU/STU after the period of five years or when the Regulatory Commission is satisfied that the situation is right to introduce such competition (as referred to in para 5.1) would also be determined on the basis of competitive bidding.*

(7) After the implementation of the proposed framework for the inter-State transmission, ***a similar approach should be implemented by SERCs in next two years for the intra-State transmission****, duly considering factors like voltage, distance, direction and quantum of flow."*

Clause 7.1 Infrastructure

*"(8)**Metering compatible with the requirements** of the proposed transmission tariff framework should be established on priority basis. The metering should be compatible with ABT requirements, which would also facilitate implementation of Time of Day (ToD) tariffs."*

Clause 7.2 Approach for Transmission Loss

"(1) Transactions should be charged on the basis of average losses arrived at after appropriately considering the distance and directional sensitivity, as applicable to relevant voltage level, on the transmission system. Based on the methodology laid down by the CERC in this regard for inter-state transmission, the Forum of Regulators may evolve a similar approach for intra-state transmission.

The loss framework should ensure that the loss compensation is reasonable and linked to applicable technical loss benchmarks. The benchmarks should be determined by the Appropriate Commission after considering advice of CEA.

It would be desirable to move to a system of loss compensation based on incremental losses as present deficiencies in transmission capacities are overcome through network expansion.

*(2) The Appropriate Commission **may require necessary studies to be conducted to establish the allowable level of system loss for the network configuration**, and the capital expenditure required to augment the transmission system and reduce system losses. Since additional flows above a level of line loading leads to significantly higher losses, CTU / STU should ensure upgrading of transmission systems to avoid the situations of overloading. The Appropriate Commission should permit adequate capital investments in new assets for upgrading the transmission system."*

Clause 7.3 Other issues in Transmission

"(1) Financial incentives and disincentives should be implemented for the CTU and the STU around the key performance indicators (KPI) for these organisations. Such KPls would include efficient network construction, system availability and loss reduction.

(2) All available information should be shared with intending users by the CTU /STU and the load dispatch centers, particularly information on available transmission capacity and load flow studies."

Thus, the proposed transmission pricing framework under MYT regime will have to be in line with National Electricity Policy guidelines and in conformity with the conditions outlined under the Tariff Policy. Further, the proposed transmission pricing framework will have to be compatible with various provisions pertaining to Transmission Capacity Rights of Transmission System Users (TSUs), their trading, non-utilisation, part-utilisation, excess utilization, etc., as outlined under Open Access Regulations notified by the Commission from time to time. It would be equally important to identify various elements and components comprising the Intra-State Transmission System in order to establish Transmission Capacity Rights and utilization thereof, for which, transmission charges shall be levied.

5.2.2 Guidelines for Private sector participation in Transmission

"Guidelines for Encouraging Competition in Development of Transmission Projects" were notified on April 13, 2006 in pursuance of Tariff policy, by Ministry of Power vide Resolution No. 11/5/2005-PG(ii) published in the Gazette of India, Part I, Section 1. Subsequently on 14th June 2006, the Empowered Committee was constituted by the Ministry of Power to give effect to and implement the provisions of "Guidelines for Encouraging Competition in Development of Transmission Projects".

Thereafter, on 17th April, 2006 the "Tariff based Competitive-bidding Guidelines for Transmission Service" was notified in pursuance of Tariff Policy, by Ministry of Power vide Resolution No. No. 11/5/2005-PG(i) published in the Gazette of India, Part I, Section 1.

The salient features of the "Guidelines for Encouraging Competition in Development of Transmission Projects" is as follows -

- *In view of the provisions in EA 2003, NEP and NTP the following plans will be* *prepared:*

a) *Perspective Plan for three five year plan periods will be prepared by CEA.*

b) *Short Term Plan corresponding with one five year plan period will be prepared by CEA.*

Both these plans form part of the National Electricity Plan.

c) *Network Plan will be prepared by the CTU based upon the National Electricity Plan.*

- *An empowered committee will be formed with the following functions.*

  a) *To identify projects to be developed under this Scheme.*

  b) *To invite bids and to select a developer*

  c) *To facilitate finalization and signing of Transmission Service Agreement (TSA) between the developer and the concerned utilities.*

  d) *To facilitate development of projects under this Scheme.*

- *Once the Perspective Plan, covering three five year plans, the Short Term Plan and the Network Plan have been prepared, some of these projects will be identified as projects to be covered under this Scheme for competitive bidding.*

- *Identification of projects under this Scheme will be done in such a way that it results in a balanced mix of both difficult and less difficult projects.*

- *The selection of developer for identified projects would be through tariff based bidding for transmission services according to the guidelines issued by the Ministry Of Power under section 63 of the Electricity Act, 2003.*

- *The selected private investor shall approach the Appropriate Commission, within a period of 30 days, for grant of transmission license.*

- *A Transmission Service Agreement (TSA) will be signed among the private licensee and the concerned utilities for payment of the transmission charges finalized and accepted by the appropriate Commission on the basis of competitive bidding.*

- *As far as intra-state projects are concerned the state governments may adopt these guidelines and may constitute a similar committee for facilitation of transmission projects within the state by private investors.*

Thus, as mentioned in the last point of the salient features, the "Guidelines for Encouraging Competition in Development of Transmission Projects" provides for formation of a committee to coordinate the Competitive Bidding process at the State level.

Further, the "Tariff based Competitive-bidding Guidelines for Transmission Service" provides as under:-

> *"3.2. For procurement of transmission services, required for inter-state transmission, the Central Government shall notify any Central Government Organization/ Central Public Sector Undertaking to be the BPC. The BPC will be notified by the Ministry of Power and nomination of BPC will be for a period of three years at a time. It will be open for Ministry of Power to review the nomination of BPC at any time. For immediate implementation of these guidelines the Empowered Committee constituted as per the provisions of the "Guidelines for encouraging competition in development of Transmission Projects" will be the BPC till any other organization is nominated as BPC by the Ministry of Power.*
>
> *3.3. For procurement of transmission services required for intra-state transmission, the appropriate State Government may notify any Organization/ State Public Sector Undertaking especially engaged for this purpose by the appropriate state government or BPC notified by the Central Government to be the BPC for the state." ... (Emphasis added)*

Thus, the responsibility of State Government to notify an Organisation for coordinating the procurement of transmission services required for intra-State transmission is clearly specified in the above referred guidelines issued by MOP. The Commission has given timely recommendations and requested the Government of Maharashtra regarding notification of such an Organisation, foreseeing the growing interest of private participation in the Transmission sector of the State. The relevant matters of the recommendation given by the Commission are discussed in the following section.

5.2.3 Commission's recommendations to GOM on appointment of BPC

The Commission has recommended to GOM that in line with the aforesaid Resolution No. 11/5/2005-PG(ii), dated April 13, 2006 and Resolution No. 11/5/2005-PG(i), dated

April 17, 2006, of the Ministry of Power (GoI), the State Government of Maharashtra may notify any Organization/ State Public Sector Undertaking for procurement of transmission services required for intra-state transmission. However, the GOM is yet to notify any such Organisation/undertaking for the purpose.

In the meanwhile, the Commission received two applications from M/s Jaigad Power Transco Ltd. and M/s Adani Power Ltd for grant of transmission licence for development of Transmission network in the State. The Commission issued a Transmission license to M/s Jaigad Power Transco Ltd. and to M/s Adani Power Ltd. upon perusal of due regulatory process outlined under its applicable regulations for grant of transmission licence.

In view of above developments, the Commission has given timely recommendation to GOM on the matter to take urgent steps as necessary, with intimation to the Commission. The Commission has sent the recommendations to the GOM through letters dated September 12, 2008 and April 21, 2009. Relevant sections of the letter dated April 21, 2009 are reproduced as below.

> *"In view of increasing number of private sector interest in undertaking transmission activities in the State, it is preferred that GOM takes urgent action for implementing the "Guidelines for Encouraging Competition in Development of Transmission Projects", and the "Tariff based Competitive-bidding Guidelines for Transmission Service". In case the Government of Maharashtra, has taken any such steps the same may be intimated to the MERC, as such actions would have a bearing on the present proceedings related to the application received from Adani Power Ltd. for grant of Transmission Licence. In this regard, it may kindly be noted that it will not be in the interests of justice and in public interest, to hold back grant of licence for transmission of electricity from generating stations as it will immobilize evacuation of power generated and bring it to a stand still; put investment made into setting up of the generating capacities in jeopardy; defeat the objective of the Electricity Act, 2003. At the same time, the provisions of the Tariff Policy as stated above needs to be implemented. These briefly stated are as under:-*
>
> *(1) Investment by transmission developer other than CTU/STU would be invited through competitive bids.*

Even for the Public Sector projects, tariff of all new generation and transmission projects should be decided on the basis of competitive bidding after a period of five years or when the Regulatory Commission is satisfied that the situation is ripe to introduce such competition. This stipulation under paragraph 5.1 read with 7.1 (6) of the Tariff Policy has to be taken to mean that till the year 2011 (or when the Commission is satisfied that the situation is ripe to introduce such competition), Government Companies in which not less than fifty-one per cent of the paid-up share capital is held by the Central Government, or by any State Government or Governments, or partly by the Central Government and partly by one or more State Governments and including a company which is a subsidiary of a Government company as thus defined, may be granted transmission license without the need to be selected on the basis of competitive bidding."

5.2.4 Salient features of CERC's proposed Marginal Participation Method

Central Electricity Regulatory Commission (CERC) has recently come out with an Approach Paper on formulating pricing methodology for Inter-State transmission, for initiating the process of modifying the Regulations to make it in line with the requirements of NEP and NTP. The salient features of the Approach P aper are given below.

Pricing approaches considered in the Approach Paper

- **Marginal Participation Method**
- **Average Participation Method**
- **Zone-to-Zone Method**

(All three methods are based on load flow studies indicating the use of the system, but use different approaches for determining the use of the network by various users of the transmission system.)

Approach Recommended and its salient features

<u>Marginal Participation (MP) Method</u>

1. Transmission prices determined using MP method measure how much each user is benefiting from the existence of various network facilities.

2. MP method directly computes the relative use of each network branch by generators and demand customers (The split of transmission charges between generators and demand customers needs to be specified by the user in other models). This provides clear locational signals to generation and demand customers.
3. The MP method considers the meshed network as a common use facility. Utilization of the network branches are determined based on actual power flows on the network. This obviates the need for arbitrary assumptions.
4. Transmission charges determined using MP method are Point Tariffs, indicating that each user of the network will be required to pay a fixed charge depending on its location in the network.
5. These charges are in Rs/MW/month depending on the location of generator / demand customer and provide clear signals based on distance and direction.
6. Chargeable capacity: determined based of forecast of generation level by generators and demand level by the demand customers. (Transmission charges indicated in Rs/MW/month are multiplied by the chargeable capacity to determine monthly charges.)
7. Implementation of Point Tariffs:
    - Generators and demand customers will be required to sign alternate commercial agreements - Connection and Use of System Agreement (CUSA) (alternate to existing BPTA)
    - Apart from the need for specifying the destination of power for a generator and the source of power for a demand user, other key provisions of a BPTA would be retained in the CUSA.
    - The need for separate charges for long term and short term open access is obviated.
8. The transmission tariffs so determined do not lead to pancaking and hence, send cost-reflective signals for efficient inter-State and inter-regional trading.
9. Proposed mechanism considerably simplifies the allocation of transmission charges between parties involved in electricity trades on the power exchange.

The generators selling power on the exchange can internalize the transmission charges in their price bids, whereas the demand customers can be charged transmission charges

separately based on short-term access approved.

This Approach Paper is under the discussion stage and CERC is yet to come out with the final Regulations based on the recommendations of the paper. While formulating the new Regulations in this matter, views of various stakeholders are also to be taken into consideration and the regulatory process is still underway. The requirements and feasibility of such an approach to be adopted at the State level is discussed in the subsequent sub-section.

5.2.5 Requirements & feasibility to introduce MP approach at State level

The Marginal Pricing method as proposed in the CERC Approach Paper for adoption at Inter-State level relies mainly on load flow analysis. Inputs to the proposed model, viz., Nodal generation information, Nodal demand information, Transmission circuits between these nodes, Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch, and the associated lengths of each line will be required to be obtained systematically from each user of the network and network service provider by the NLDC (or any other agency designated by the CERC for this purpose) for computing the transmission use of the system charges for each season annually. The following table provides various requirements to be met in order to implement the proposed MP method at the intra-State level. It also provides a comparison of the requirements for implementation at inter-State level and intra-State level.

Requirements of MP method	**CERC approach**	**Required Intra-State approach**
Nodal generation information	Obtained based on the generation levels committed by each generator under specific – seasonal peak and other than peak conditions identified a-priori by the NLDC.	Generator-wise generation levels to be forecasted. Seasonal peak and other than peak to be identified at State level.

Requirements of MP method	**CERC approach**	**Required Intra-State approach**
Nodal demand information	Data based on demand that various beneficiary utilities (SEBs / distribution Utilities) forecast to occur at the specific peak and other than peak conditions identified by the NLDC.	Licensee-wise demand to be forecasted at different peak and other than peak conditions to be identified at State level.
Transmission circuits between these nodes	To be supplied by the CTU based on transmission expansion plan data prepared in coordination with the CEA, STUs/SEBs and transmission licensees and complemented with periodic updates at frequencies to be determined by the CERC.	To be obtained based on intra-State transmission planning as prepared by STU and in co-ordination with other transmission utilities with periodic updates.
Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch		
The associated lengths of each line		
Identification of reference nodes	Virtual distributed reference node used	Reference node to be identified
Load flow analysis	The transmission charges in Rs/MW for each season at each node would be determined based on the load flow studies	The transmission charges in Rs/MW for each season at each node to be determined based on the load flow studies

Further, suitable contractual framework at State level akin to CUSA (Connection and Use of System Agreement) at Inter-State level with necessary clauses should be evolved in order to factor the following.

a. Treatment of the delay in injection/drawal by grid connected entities (in the case where synchronisation of a generator is delayed)
b. Treatment of the delay in creation of transmission capacity

Other major issues to be addressed for implementation of MP method of Transmission Pricing Mechanism at State level are: a) Identification of Nodes and Interface points, b) Energy accounting and Measurement, and c) Separation of assets into connection assets and grid assets.

Identification of Nodes and Interface Points amongst Transmission System Users

The energy exchange amongst the parties (actual and scheduled) needs to be monitored, measured and accounted for in order to settle the various transactions. The proposed Transmission Pricing mechanism envisages clear demarcation of boundary (or interface points/nodes) between various transmission licensees and transmission system users including generating companies and distribution licensees.

In addition, with extension of the ABT regime within the State and grant of open access, and introduction of Balancing and Settlement Code, clear understanding of Interface Points and identification of 'generation node' and 'demand node' over InSTS becomes essential. This is because there may not always be a perfect match between the generation and the consumption by the consumers (open access and others) of every generator. Under the circumstances, this energy imbalance has to be accounted for on a system wide basis amongst the contracting parties and the accurate assessment of the same is possible only if the Interface Points/nodes are identified adequately.

Separation of assets into Connection assets and Core grid assets

The transmission network comprises a mesh of nodes and circuits. A node is a sub-station on the grid system where electricity is drawn or injected into the system and circuit represents the electrical link between two nodes. Nodes and circuits can be classified as 'Core grid nodes' or 'Connection nodes' and 'Core grid Circuits' or 'Connection Circuits'. The Connection Circuit would have one connection node at one end. Typically, connection node would be linked to one or limited number of customers.

Thus, entire grid network assets can be classified into Core Grid Assets and Connection Assets and the revenue requirement of these can be determined separately.

For implementation of MP method at intra-State level, separation of assets of the Transmission Utility is necessary. However, separation of revenue requirement and assets into Connection Assets and Core Grid Assets is a rigorous and intensive process and would be difficult unless appropriate accounting systems are adopted. Until accounting systems are put in place, apportionment or allocation of costs amongst connection assets and Grid assets based on technical information would be difficult.

5.3 *Key issues in Transmission for New Control Period*

5.3.1 Objectives of Transmission Pricing for New Control Period

The Transmission pricing framework under MYT regime, in addition to meeting the transmission revenue requirement, needs to be guided by key considerations such as economic and efficient use of transmission network, non-discriminatory approach, encouraging investment, supporting the development of market/trading opportunities, etc. A well designed Transmission pricing scheme should:

- Provide economic signals for efficient use of transmission resources;
- Provide economic signals for investment in transmission;
- Provide economic signals for location of new generation and loads;
- Promote efficient day to day operation of the bulk power market including power trading;
- Compensate the owner of the transmission system by meeting its revenue requirement including returns; and
- Be simple and practical.

5.3.2 Key Issues related to Transmission in next Control Period

Key issues to be addressed in respect of Transmission during next Control Period can be classified into two broad categories as under:

A] Regulating performance of transmission licensees

- How should performance of existing transmission licensees be regulated?
- What should be operating norms and performance standards for transmission licensees within State?
- How should transmission investments by transmission licensees be regulated in order to yield optimal transmission system meeting with planning standards under IEGC and State Grid Code?
- How should transmission licensees be encouraged to prioritise investments?
- How should private sector participation in transmission be encouraged?
- How should open access to use intra-State transmission network be ensured?

B] Regulating Transmission System Usage

- How should transmission system usage be defined and monitored in case of usage by various transmission system users (TSUs)?
- Whether distinction in transmission pricing be made depending on tenure of usage (long term/medium term/short term)?
- Whether distinction should be made in case of renewable energy transactions entailing transmission system use?
- What should be the mechanism for recovery for usage of intra-State transmission system for inter-State wheeling transactions?
- What should be the principles for treatment of transmission losses?
- Should the existing principles for Transmission pricing based on co-incident peak demand, denominations, recovery etc. be modified?

Above issues are deliberated in detail in subsequent sections.

5.4 *Regulating Transmission Licensees & Performance Standards*

5.4.1 Regulating Capital Investment & Optimal Investment Plan

5.4.1.1 Business Plan

In accordance with the existing MERC Tariff Regulations, 2005, the transmission licensees are required to submit an investment plan with full details of the licensee's proposed capital expenditure projects to the Commission for its approval. The Commission reviews such investment plan submitted by the Transmission Licensee, taking into consideration the prudence of the proposed expenditure and estimated impact on tariff and thereafter, either give an in-principle approval to the investment plan or rejects the investment plan whichever the Commission deems appropriate. Further, as per the existing practice, the transmission licensee should submit the details showing the progress of such capital expenditure identified in the investment plan along with the application for determination of tariff or along with the application for annual performance review for assessment of such progress.

However, during the first control period, the Commission observed that, utilities in the shade of capital expenditure are engaged in building their asset base and is contentedly neglecting or giving less significance to the need for improving their performance efficiency. In the wake of such a situation, ABPS Infra find it appropriate to propose that the Transmission Utilities instead of submitting just an investment plan should come up with a comprehensive Business plan which will set the track for necessary growth as well as systematic improvement in their performance efficiency. ABPS Infra proposes that such a Comprehensive Business plan should cover the following factors.

a) Capital Investment Plan

b) Financing Plan

c) Loss Reduction Plan

d) Human Resource Management Plan

Such business plan should be formulated in a way to ensure the following

a) Improvement in efficiency and availability of transmission system;

b) Reduction transmission loss;

c) Motivate personnel to enhance performance and increase employee contribution;

d) Increase system reliability, safety and security;

e) Increase transparency and accountability of operations;

f) Promote business development to improve financial standing;

g) Improve metering to achieve optimal control of the transmission system;

It is proposed that the Transmission utility should submit the Business plan before the start of the control period for approval. In its Business Plan filings, the Utility should submit and propose the trajectory for the achievement of quality targets.

5.4.2 Regulating Operating Performance: O&M Norms

5.4.2.1 Historical Background for Development of Norms for O&M expense

The Maharashtra State Electricity Transmission Company Limited (MSETCL) under its MYT application for the earlier Control Period (FY 2007-08 to FY 2009-10) had projected O&M expenses considering the O&M norms developed by the Central Electricity Regulatory Commission (CERC) for the regional transmission network. However, the Commission had opined that since the configuration, network topology, organisation structure, compensation plan, and maintenance practices, etc. are different for the State transmission system as against that applicable for the regional transmission system, the relevance of such norms in the context of State transmission system should be first studied and it may not be appropriate to consider the regional O&M norms as the basis for projecting O&M expenses for State transmission network. The relevant extract of the Commission's MYT Order (Case No. 67 of 2006) is as under:

> *"The Commission has analysed MSETCL's request for considering the norms of O&M on the basis of cost per bay and ckt-km. The Commission is of the opinion that any such norm could be developed by studying the past trends of O&M expenses for MSETCL itself and other State Transmission Utilities, rather than comparison with norms applicable for PGCIL as stipulated by the CERC. Hence, the Commission made a detail analysis of the O&M expenditure based on the historical trend of O&M expenditure by MSETCL, and computed O&M expenditure based on cost per bay and per ckt-km. By applying such*

methodology, the Commission observed that the average O&M expenditure per bay works out in the range of Rs 8-10 Lakh/Bay and around Rs 0.3 Lakh/Ckt-Km. Further, the Commission has carried out a detailed analysis of the norms being prescribed/adopted by other State Electricity Regulatory Commissions (SERCs) of comparable States like Andhra Pradesh, Madhya Pradesh, Gujarat, etc. The Commission found that the O&M expenditure being allowed for MSETCL in the past years is on the higher side as compared to transmission utilities of other States, hence, there does not appear to be any grounds for any upward revision in the norms for O&M expenditure.

The Commission is of the opinion that any other suitable norms for allowance of O&M expenses could be adopted after undertaking a thorough study of the O&M expenditure, the cost drivers of the same, and the comparison of the per bay and per circuit km norms across different transmission Utilities, through a separate process. Till any such norm for O&M expenditure is determined, the Commission is considering the individual elements of O&M expenditure based on the increase linked to inflation indices for the first Control Period of MYT."

The Commission also outlined the principles that could be considered for derivation of O&M norms as under:

1. *"The total O&M Costs for all the years should be allocated between bays and line. The Commission directs the Licensee to submit the details of O&M expenses per circuit Kilometer of line length and per bay for the last five years, if data is not available on the same, then the licensee should submit the asset details of bays and assets details of lines, along with definition as to what constitutes a bay as per the licensee. This information would help derive a ratio which the Commission would use to allocate the total O&M Costs to bays and lines.*

2. *Based on the above information, the O&M costs per bay and O&M Costs per circuit-km for the past years would be computed by dividing the O&M cost for bays / lines with total number of bays / total line length in km. The Commission directs MSETCL to submit information regarding the number of bays and total length in circuit kilometers for every year.*

3. *The operation and maintenance expense norms for the Control Period shall be derived on the basis of the average of the actual O&M Costs per bay and O&M Costs per circuit-km for the five (5) years ending March 31, 2006, based on the audited financial statements, excluding abnormal operation and maintenance expenses, if any, subject to prudence check by the Commission.*

4. *The average of such O&M Costs per bay and O&M Costs per circuit-km shall be considered as the costs for the financial year ended March 31, 2004 and shall be escalated at the rate of a composite index that Commission would compute based on Wholesale Price Index (WPI) and Consumer Price Index for Industrial workers (CPI_IW) by assigning appropriate weights to the same, per annum to arrive at Operation and Maintenance expenses for the base year commencing April 1, 2006.*

5. *The base Operation and Maintenance expenses for each subsequent year shall be escalated at the rate of the composite index that Commission would compute as mentioned above to arrive at permissible O&M Costs per bay and O&M Costs per circuit-km for the control period. These values would be reviewed as part of the Annual Performance Review in terms of productivity levels and efficiency factors."*

Subsequently, the Hon'ble Appellate Tribunal for Electricity (ATE) in its Judgment in Appeal No. 76 of 2007 ruled that projection of employee expense, R&M expense, and A&G expense for the remaining duration of the Control Period should be carried out by extrapolating the actual audited expenses for FY 2006-07 subject to prudence check and this approach shall be continued **till norms are finalised**. Thus, it is important to stipulate norms for O&M expenses before commencement of the next Control Period.

5.4.2.2 Premise for Development of Norms for O&M expenses

ABPS Infra proposes to derive the O&M norms for the transmission licensees in the State of Maharashtra based on its judgement of the relationship between the drivers of O&M expenses and parameters such as line length in circuit km, number of bays, and transformation capacity in MVA. O&M expenses comprise employee expenses, repair & maintenance expenses and administrative & general expenses. With increase in transmission capacity and corresponding increase in asset base, the manpower resources and repairs and maintenance activities needs to be augmented adequately to cater to the enhanced maintenance requirement (preventive and break-down) of the asset base. There is a direct co-relation between O&M expenses and on-line transmission/network capacity, number of bays and transmission line length (ckt-km) put into service, as is evident from the subsequent analysis.

In order to derive the O&M Norms, ABPS Infra has adopted following four step approach as presented below:

- Comparison of Network Configuration and other technical parameters across various State level Transmission Utilities in India.
- Comparison of O&M expense components and structure across State level Transmission Utilities in India
- Comparison of physical, technical and cost parameters across Intra-State Transmission licensees within Maharashtra.
- Comparison of O&M expenses of the intra-State Transmission Licensees of Maharashtra with that of CTU (PGCIL)/CERC norms

5.4.2.2.1 Comparison of Network Configuration and other Technical parameters across State level Transmission Utilities

Since O&M expenses of a transmission Utility are related to its physical network configuration, it is necessary to compare the physical configuration of various Utilities before undertaking comparative analysis of the O&M expenses across State Transmission Utilities. Accordingly, in this Section, ABPS Infra has provided a comparison of various technical/physical parameters of selected Transmission Utilities, which depicts the similarities and dissimilarities of their network configuration amongst various transmission licensees. For comparison purposes, at least two Transmission Utilities each from the Northern Region, Southern Region, Eastern Region and Western Region have been considered. The Transmission Utilities considered for the purpose of analysis are Transmission Corporation of Andhra Pradesh Limited (AP Transco), Karnataka Power Transmission Corporation Ltd (KPTCL), Gujarat Energy Transmission Co. Ltd (GETCO), Rajasthan Rajya Vidyut Prasaran Nigam Ltd (RVPNL), Orissa Power Transmission Co. Ltd (OPTCL), West Bengal State Electricity Transmission Co. Ltd (WBSETCL) and MSETCL. The primary objective of this exercise is to identify those

State level Transmission Utilities, which are having comparable network configuration, so that appropriate norms for O&M expenses can be derived based on the analysis of State level Transmission Utilities operating on comparable platform.

The technical/physical profile of a Transmission Utility mainly includes the following.

a. Length of Transmission Line (in Ckt Km)

b. Transmission capacity (in MVA)

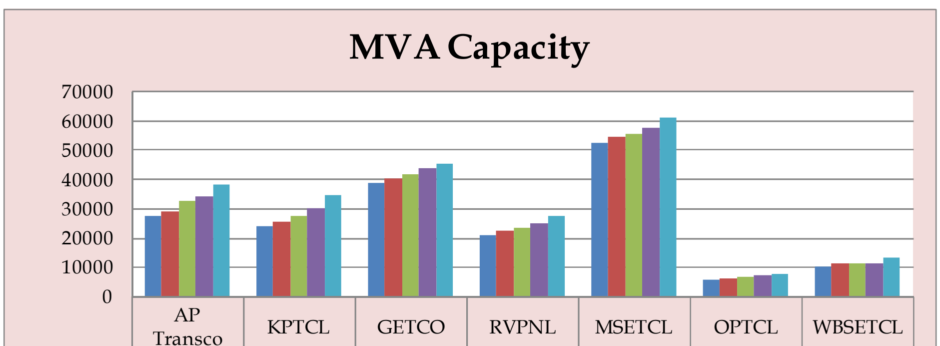
c. Number of substations/Number of bays

d. Operating Voltage levels

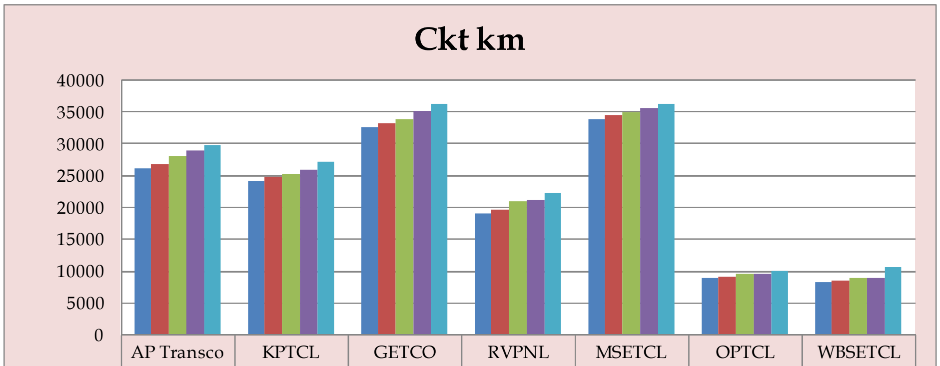
e. Energy handled (MU)

f. Average/Peak demand catered by the transmission system (MW)

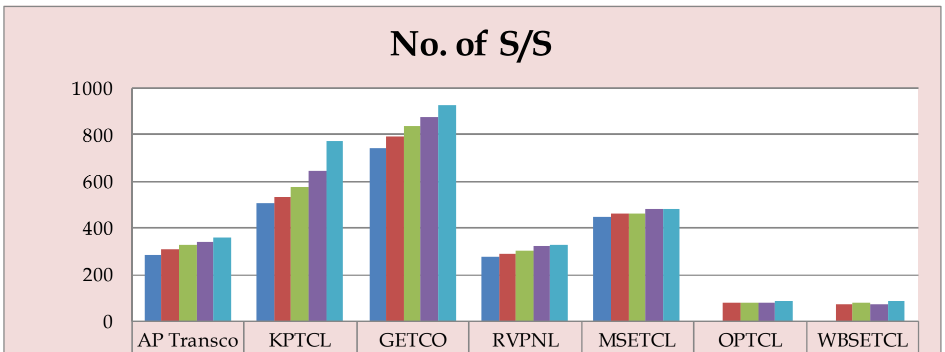
The following graphs provide a snapshot of the growth of Transmission Utilities in terms of their grid substation capacity (MVA), transmission line length (ckt-km) and number of substations (no.) during the period from FY 2003-04 to FY 2007-08. The transmission utilities considered for this comparative analysis are APTransco, KPTCL, GETCO, RVPNL, MSETCL, OPTCL and WBSETCL.



	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
2003-04	27346	23790	38755	20760	52449	5650	10109
2004-05	28886	25422	40351	22515	54485	6050	11129
2005-06	32486	27434	41964	23697	55759	6805	11166
2006-07	34475	30335	43841	25190	57713	7050	11186
2007-08	38200	34816	45380	27429	61530	7430	13289



	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
2003-04	26228	24221	32749	19065	34026	8987	8305
2004-05	26883	24857	33348	19881	34630	9267	8532
2005-06	28187	25301	34016	20983	35028	9573	8926
2006-07	28950	26112	35168	21358	35626	9719	9129
2007-08	29957	27212	36388	22313	36287	10075	10760



	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
2003-04	289	508	746	281	454		
2004-05	310	536	797	292	466	85	77
2005-06	329	578	838	305	468	85	80
2006-07	345	650	880	327	486	85	79
2007-08	362	774	930	329	484	88	89

It may be noted that the statistics available for number of sub-stations in case of GETCO and KPTCL include 66/33 kV substations as well, unlike other State utilities wherein only 132 kV and above substations are included in the statistics.

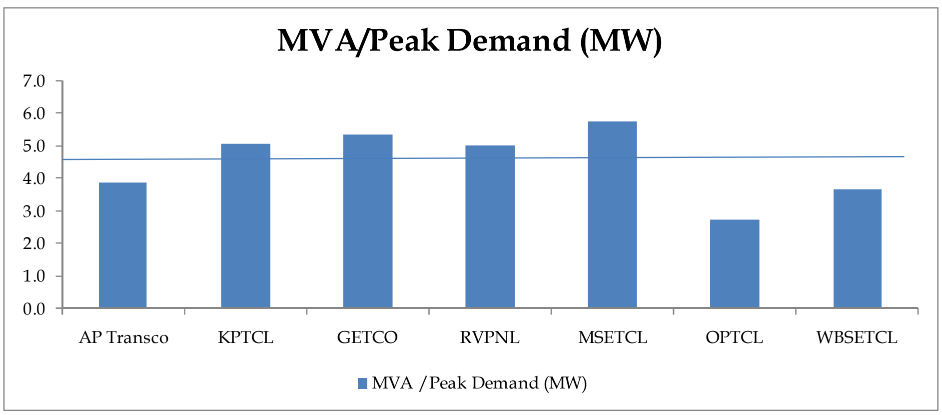
In order to compare the technical parameters of selected Transmission Utilities, certain ratios have been derived for various physical parameters as outlined below:

1. Ratio of Grid Substation Installed capacity (in MVA) to Peak demand catered by the network (in MW)
2. Ratio of Energy units handled (in MU) to Grid Substation Installed capacity (in MVA)
3. Ratio of Energy units handled (in MU) to Transmission line length (in ckt km)

4. Ratio of transmission line length (in ckt km) to number of substations (no) under the respective Utility.
5. Ratio of Grid Substation installed capacity (in MVA) to number of substations (no) under the respective utility.

The parameters considered here are based on the average of five years data for the period from FY 2003-04 to FY 2007-08.

1. **Grid Substation installed capacity (MVA) / Peak Demand (MW)**

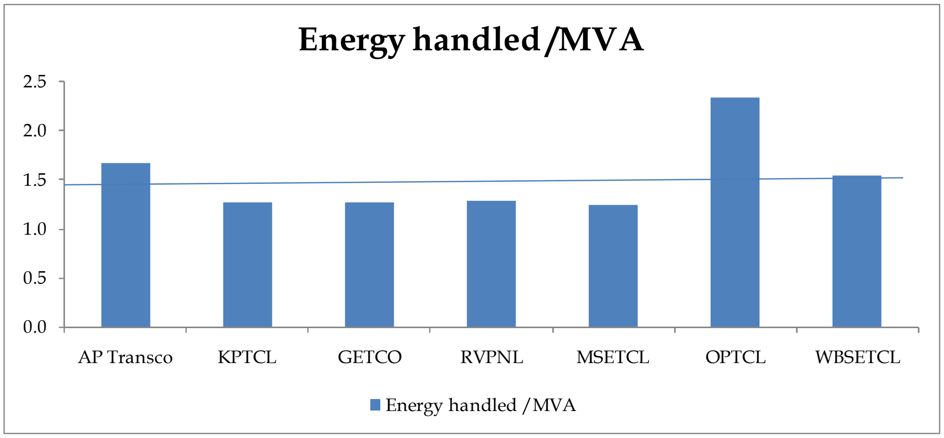


	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
MVA /Peak Demand (MW)	3.9	5.1	5.3	5.0	5.8	2.7	3.6

The average ratio of Grid Substation capacity (MVA) to peak demand catered (MW) across the Utilities is 4.5 as against that for MSETCL, which is 5.8. The ratio is highest for MSETCL and is lowest for OPTCL. However, ratio of installed capacity of Grid Substations (MVA) to the catered peak demand (MW) is comparable in respect of MSETCL, KPTCL, GETCO and RVPNL.

2. **Energy Units Handled (MU) / MVA capacity**

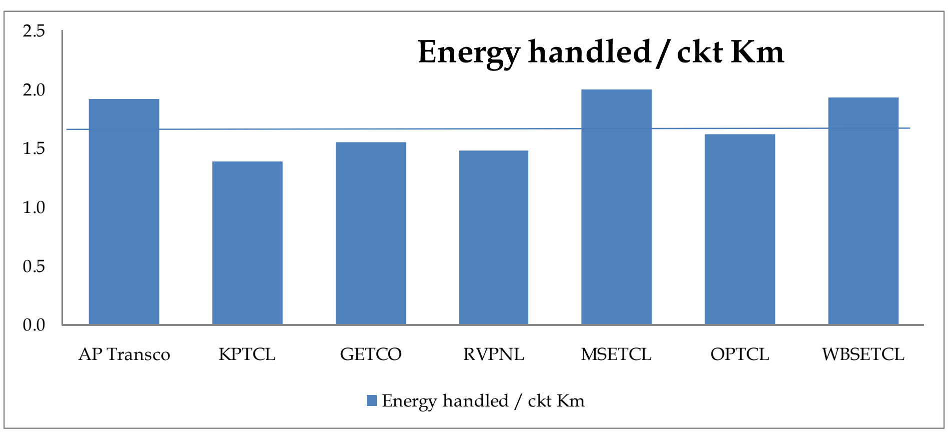
Another important physical parameter considered for comparison of configuration of network of Transmission Utilities is the energy handled or energy transmitted through the network. The ratio of Energy units handled (MU) to Grid Substation Capacity (MVA) and ratio of Energy units handled (MU) to transmission line length (ckt km) is presented in the following charts across Utilities.



	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
Energy handled /MVA	1.7	1.3	1.3	1.3	1.2	2.3	1.5

The average ratio of energy units handled (MU) to Grid substation capacity (MVA) across the Utilities is 1.5 as against that for MSETCL, which is 1.2. The ratio is lowest for MSETCL at 1.2 and highest for OPTCL at 2.3. However, ratio of energy units handled (MU) to installed capacity of Grid Substations (MVA) is comparable in respect of MSETCL, KPTCL, GETCO and RVPNL.

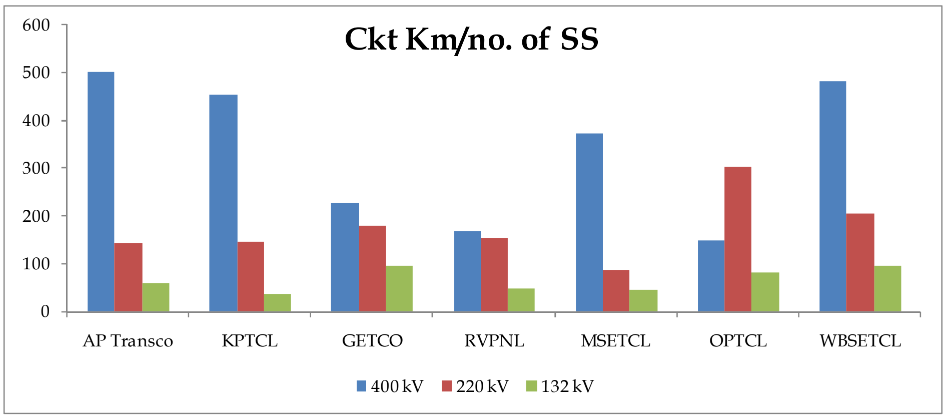
3. **Energy units handled (MU) / transmission line length (ckt km)**



	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
Energy handled / ckt Km	1.9	1.4	1.6	1.5	2.0	1.6	1.9

The average ratio of energy units handled (MU) to transmission line length (ckt km) across the Utilities is 1.7 as against that for MSETCL which is 2.0. The ratio is highest for MSETCL at 2.0 and lowest for KPTCL at 1.4.

4. **Transmission Line length (ckt km)/No of substations (at various operating voltage levels)**

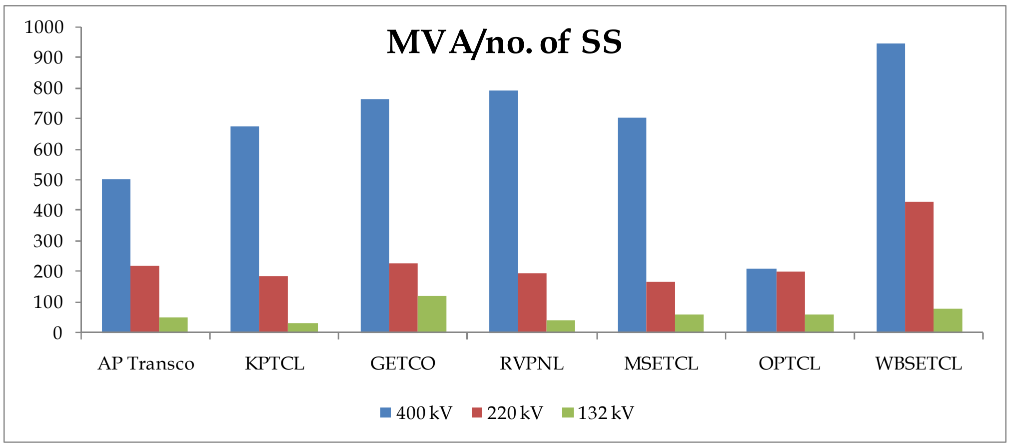


	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
400 kV	502.97	454.66	227.37	167.49	373.37	147.33	482.75
220 kV	143.88	145.73	180.60	154.21	86.33	302.19	204.92
132 kV	57.83	36.63	94.78	46.98	45.69	81.32	95.65

The above graph shows the variation of ratio of transmission line length (ckt km) to number of substations (no) for different voltage levels across the selected Utilities. A broad comparison across the Utilities reveals that, the ratios show less variation at 132 kV voltage level of operation, particularly amongst MSETCL, RVPNL, KPTCL and APTransco. At 220 kV voltage level of operation, the variation of such ratios shows a larger variation compared to variation at 132 kV, however, the same is comparable amongst APTransco, KPTCL, GETCO and RVPNL. However, at 400 kV voltage level of operation, there is a wide variation of the ratio across the Utilities with lowest ratio at 147 in case of OPTCL and highest ratio at 503 in case of APTransco. Thus, the network configuration of Utilities in terms of transmission line length and number of substation

<u>is more uniform at lower voltage levels of operation whereas the network configuration is uneven at higher voltage levels of operation.</u>

5. **Grid Substation capacity (MVA) / No of substations (at various operating voltage levels)**



	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
400 kV	500.25	676.70	762.64	792.00	701.81	210.00	945.00
220 kV	217.82	187.36	227.88	193.39	169.68	200.00	427.32
132 kV	49.12	32.06	119.21	44.01	60.35	61.02	79.74

The above graph depicts the comparison of ratio of MVA capacity to the number of substations of the Transmission Utility. The variation of this ratio across various Utilities is minimal at lower voltage levels of operation. <u>However, the configuration in terms of MVA capacity and number of substations at higher operating voltage is somewhat uneven in nature.</u>

5.4.2.2.2 *Inference: Comparison of network parameters*

Based on the above comparison of network configuration of selected transmission Utilities across various States, certain inferences can be drawn as under:

a) While comparing voltage wise configuration of the selected transmission Utilities, it is seen that the Utilities have a comparable technical configuration at lower voltage levels (220 kV and below) of operation whereas the homogeneity is found to be lower at higher voltage level (440 kV).

b) The selected transmission Utilities are broadly comparable despite certain distinct characteristics shown by some Utilities.

c) The comparison of the above ratios and technical parameters reveals that on aggregate level represented by ratios such as (i) grid substation capacity (MVA) to peak demand catered (MW) (ii) energy units handled to grid substation capacity (iii) energy units handled to transmission line length (ckt km) etc., MSETCL is almost at par with the physical configuration of other transmission Utilities considered for comparison.

d) However, significant differences exist in terms of network configuration at different voltage levels. The network configuration of Utilities in terms of transmission line length and number of substation is more uniform at lower voltage levels of operation whereas the network configuration is uneven at higher voltage levels of operation. The capital cost and operating costs at different voltage levels such as 400 kV, 220 kV, 132 kV etc. vary significantly. In view of above, although catered demand (MW) or energy units handled (MU) are comparable across utilities, the norms for operation will depend on composition of network, viz. transmission lines, substations and number of bays etc. at various voltage levels.

e) Thus, network topology and configuration at various voltage levels shall play key role in determining the O&M norms for each transmission utilities. While broad parameters in terms of units handled and peak demand catered is comparable to installed grid substation capacity (MVA) and transmission line length (ckt km) across transmission Utilities, the difference in network topology and configuration at various voltage levels (400 kV, 220 kV and 132 kV) is evident across transmission Utilities.

f) Hence, it may be noted that while benchmarking across transmission Utilities at aggregate level can be undertaken, it is preferable to derive norm for each transmission Utility considering its historical performance, its network topology/configuration, historical growth pattern and cost structure, etc.

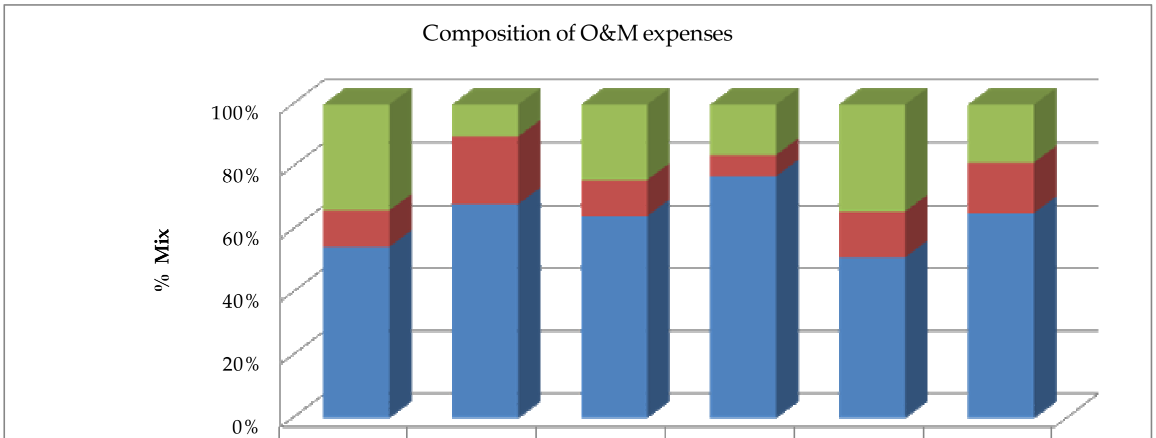
5.4.2.2.3 *Comparison of O&M Cost Components and cost structure across transmission Utilities*

The various cost components of O&M expenses and structure thereof in respect of these transmission Utilities can also be compared in a manner similar to the comparison of the physical network configuration and other technical parameters of various transmission Utilities as undertaken above. The Table below gives a comparison of O&M expense components across various transmission Utilities for FY 2007-08.

Particulars	APTransco	KPTCL	GETCO	RVPNL	MSETCL	WBPTCL
Employee Expenses	110.23	168.81	232.08	257.35	248.44	51.53
A&G Exp	23.31	53.34	41.5	22.81	70.62	12.72
R&M Exp	68.21	25.2	86.65	53.73	165.35	14.59
Net O&M Expenses (Rs Crore)	**201.75**	**247.35**	**360.23**	**333.89**	**484.41**	**78.84**
Op. GFA, (Rs Crore)	5104.74	4,360	4865.17	3951.89	8965.25	2302.15
O&M expense as % of Op. GFA	**4.0%**	**5.7%**	**7.4%**	**8.4%**	**5.4%**	**3.4%**

The ratio of O&M expenses as a percentage of Opening GFA in respect of various transmission Utilities is presented in the above Table. In case of MSETCL, the ratio amounts to 5.4% while average for above Utilities amount to 5.7%. However, it may be noted that the O&M expense in respect of RVPN (8.4%) also includes component of terminal benefit liabilities on account of contribution to pension and gratuity as on date of Transfer Scheme 19.7.2000 for all licensees within the State as per notified Transfer Scheme.

Further analysis of various cost components of O&M expenses, namely employee expenses, A&G expenses and R&M expenses is presented in the following chart.



	APTransco	KPTCL	GETCO	RVPNL	MSETCL	WBSETCL
R&M Exp	68.21	25.2	86.65	53.73	165.35	14.59
A&G Exp	23.31	53.34	41.5	22.81	70.62	12.72
Employee Expenses	110.23	168.81	232.08	257.35	248.44	51.53

It can be inferred from the above comparison that percentage mix of various O&M components such as Employee expenses (55% - 75%), A&G expenses (10% - 25%) and R&M expenses (15% - 30%) are less comparable across various State Transmission Utilities. From the above comparisons of physical configuration and O&M expenses across various State Transmission Utilities, it is evident that the parameters are less comparable across State transmission utilities.

We have also attempted to undertake comparison of various cost components of O&M expense across transmission utilities on **Per Unit basis**, which is presented below. Further, we have compared the variation over the two year period for each utility over FY07 and FY08 as under:

Particulars	**APTransco**		**KPTCL**		**GETCO**		**RVPNL**		**MSETCL**		**OPTCL**	
(approved Net O&M expense)	2006-07	2007-08	2006-07	2007-08	2006-07	2007-08	2006-07	2007-08	2006-07	2007-08	2006-07	2007-08
PU Employee Expenses , (Paise/Unit)	1.50	1.78	4.23		5.97	4.03			3.80	2.79	6.85	7.50
PU A&G Exp, (Paise/unit)	0.41	0.38	1.34		0.58	0.72			0.54	0.79	1.03	0.85
PU R&M Exp, (Paise/unit)	1.20	1.10	0.63		1.13	1.50			2.18	1.85	1.52	2.54
PU Net O&M Expenses (Paise/unit)	**3.11**	**3.26**	**6.19**	**6.40**	**7.68**	**6.25**	**9.89**	**9.22**	**6.51**	**5.43**	**9.40**	**10.89**
Avg. PU O&M Expense (Paise/Unit)	**3.18**		**6.29**		**6.97**		**9.55**		**5.97**		**10.14**	

Per unit approved O&M expenses for transmission utilities on an average basis has varied from 3.18 Paise/unit (APTransco) to 10.14 Paise/unit (OPTCL). In case of

MSETCL, average per unit approved O&M expense is 5.97 Paise/unit. The variation also exists in terms of composition of per unit employee expense, per unit A&G expense and per unit R&M expense across state transmission utilities.

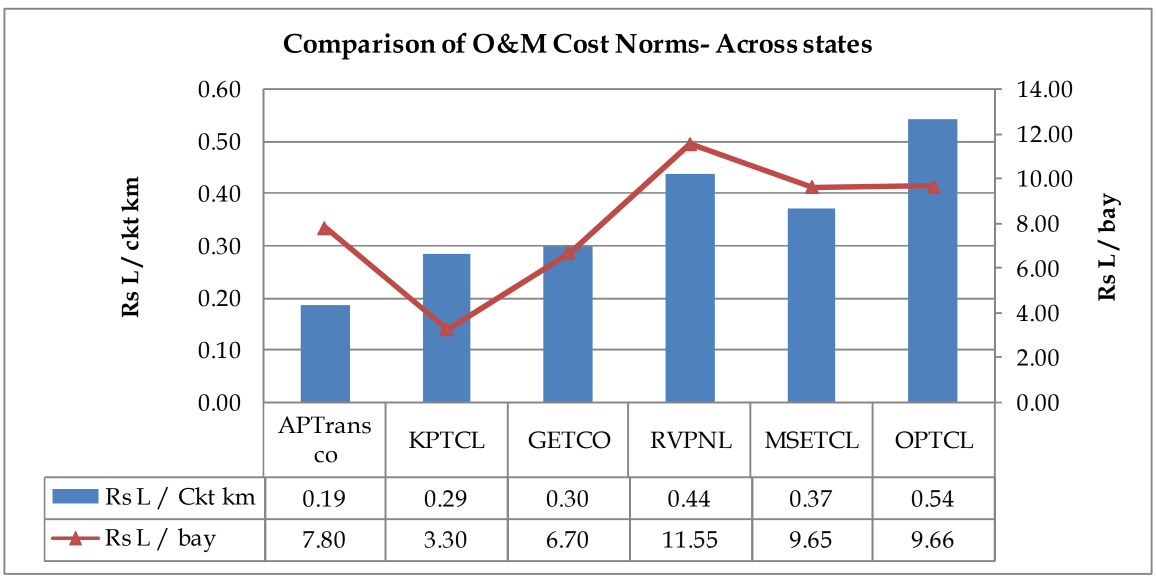
Another important point which is noted from above comparison that while energy units handled by transmission system is one of the important performance parameter, the variation in terms of per unit is significant depending on energy units handled. Thus, in case O&M norms are specified in terms of 'Per Unit' basis, there could be significant variation in allowable O&M expense in absolute terms depending on energy units handled by the transmission system within a particular year. Besides, the transmission licensee will have little control over energy units handled which is greatly influenced by generation availability and demand factors. Thus, it may not be prudent to specify O&M norms on 'Per Unit' basis.

Cost drivers for deriving norms for O&M expense:

Various components of O&M expenses such as number of employees and employee related expenses thereof, R&M expense, A&G expense shall depend on physical network parameters such as substations, transmission lines etc. The transmission line length (ckt-km) and no of substations (or bays) represents important cost drivers for the O&M expenses. The norms for O&M expenses can be derived considering these two important cost drivers in terms of Rs Lakh per bay and Rs Lakh per ckt-km. O&M expenses need to be allocated amongst substation bays and ckt-km in some ratio depending ratio of gross fixed asset base (GFA) for substation/lines and manpower required to cater to bays/lines. However, in the absence of information about asset base, manpower allocation etc., the ratio for allocation of O&M expense between transmission bays and transmission lines has been considered as 70:30 for the purpose of comparative analysis of derived O&M norms across State transmission utilities. RERC has considered a third parameter, viz., grid substation capacity (MVA) and allocated the O&M expenses amongst the three parameters, viz. transmission line length-ckt km (20%), grid substation capacity – MVA (40%) and number of bays (40%). Further, RERC has also sub-divided above norms in terms of voltage levels of transmission line (voltage-wise ckt-km – 765 kV, 400 kV, 220 kV, 132 kV) and voltage level of bays (voltage-wise no. of bays - 765 kV, 440 kV, 220 kV, 132 kV).

While voltage-wise distinction in terms of norms is desirable as R&M component of O&M expenses varies significantly depending on the voltage level, however, at this stage, it will be preferable to make distinction in terms of key cost drivers such as transmission line length and number of bays. The distinction in terms of voltage level for the purpose of O&M norms need not be made during this Control Period It is worthwhile to note that R&M cost component forms around 15%-30% of total O&M cost component.

For comparison purposes, average O&M expense norms for three years (FY 2005-06 to FY 2007-08) for each Utility have been considered. In order to derive the norms, the O&M expenses have been allocated amongst the number of bays (no) and transmission line length (ckt km) in the ratio of 70:30. Comparison of such O&M expense norms is presented in the Chart below:



5.4.2.2.4 *Inference: Comparison of Cost parameters*

Based on the above comparison of cost components of selected transmission Utilities across various States, certain inferences can be drawn as under:

a) O&M expenses as percentage of Opening GFA in respect of various transmission Utilities are comparable. However, differences due to specific cost components such as terminal benefits, accounting standard treatment, etc., exists across transmission Utilities, which need to be addressed while undertaking comparative analysis.

b) The structure of O&M expense components comprising employee expenses, A&G expenses and R&M expenses is less comparable across the State Transmission Utilities due to differences in organisation structure and cost thereof. Further, the variation in cost components (within a range), particularly for R&M expenses shall continue to exist on account of differences in network topology and other physical network parameters.

c) The transmission line length (ckt-km) and no of substation (or bays) represents important cost drivers for the O&M costs. The norms for O&M expenses can be derived considering these two important cost drivers in terms of Rs Lakh per bay and Rs Lakh per ckt-km. O&M expenses need to be allocated amongst substation bays and ckt-km in some ratio (say, 70:30) for deriving O&M expense norms thereof.

d) Voltage-wise distinction in terms of norms is not desirable at this stage.

e) Hence, while benchmarking across transmission Utilities at aggregate level can be undertaken, it is preferable to derive norm for each transmission Utility considering its historical performance, its network topology/configuration, historical growth pattern and cost structure, etc.

5.4.2.2.5 Comparison of O&M expense norms amongst the Intra-State Transmission licensees in Maharashtra

At present, the intra-State transmission system (InSTS) within Maharashtra comprises the transmission network of MSETCL, The Tata Power Company – Transmission Business (TPC-T) and Reliance Infrastructure Limited – Transmission Business (RInfra-T). The nature of Transmission Licensees varies significantly on the technical, financial and operational front. The State Transmission Utility-MSETCL, operates its assets at voltage level ranging from 66 kV to 400 kV. The transmission network of MSETCL also includes around 1500 ckt kms of HVDC lines. However, TPC-T operates its assets at a voltage level ranging from 66 kV to 220 kV and RInfra-T operates only at 220 kV voltage levels. Further, the difference is significant on the financial front, with the Net ARR approved for FY 2009-10 for MSETCL, TPC-T and RInfra-T at Rs. 1491 crore, Rs. 188 crore and Rs. 57 crore, respectively. The following Table shows a comparison of the technical configuration of the three Transmission Utilities in Maharashtra in terms of MVA capacity, transmission line length in ckt km and number of bays for FY 2008-09.

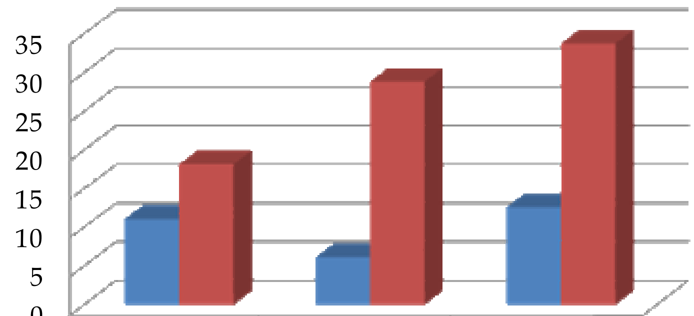
Particulars	units	MSETCL	TPC-T	RInfra-T
Transmission line length	ckt Km	36409	1191	481
MVA capacity	MVA	62459	6644	1100
no of substation	no	0	16	3
no of bays	no	3412	192	31
Transmission line length / Bays	ckt Km / bay	10.67	6.20	15.50
Substation Capacity / Bays	MVA/ bay	18.31	34.60	35.48

The ratio of Transmission line length to number of bays and the ratio of Substation capacity to number of bays have been derived to compare the technical configuration of the three transmission Utilities. The ratio brings out the structural difference in network configuration and topology amongst the three transmission licensees in the State of Maharashtra. The transmission line length (ckt-km) per bay is lowest in case of TPC-T, whereas Grid substation capacity per bay is lowest in case of MSETCL. Further, TPC-T also has underground transmission cables as part of its transmission network.

	2004-05	2005-06	2006-07	2007-08	2008-09	average
MSETCL						
ckt km/no of bays	11.69	11.33	11.09	10.77	10.67	11.11
MVA/no of bays	18.39	18.03	17.96	18.26	18.31	18.19
TPC-T						
ckt km/no of bays	6.39	6.39	6.39	5.48	6.20	6.17
MVA/no of bays	24.86	24.86	24.86	35.01	34.60	28.84
Rinfra-T						
ckt km/no of bays	8.43	8.16	15.55	15.50	15.50	12.63
MVA/no of bays	33.33	32.26	32.26	35.48	35.48	33.76

The average of such ratios for the past 5 years (FY 2004-05 to FY 2008-09) of each Utility has been computed in the Table above.

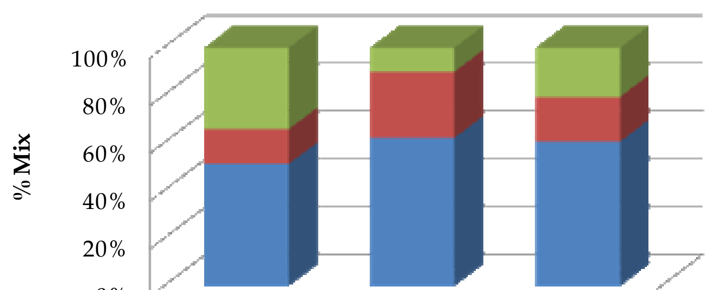
Comparison of Technical Configuration



	MSETCL	TPC-T	RInfra-T
Transmission line length (ckt km)/ Bay	11.11	6.17	12.63
Substation Capacity (MVA) / Bays	18.19	28.84	33.76

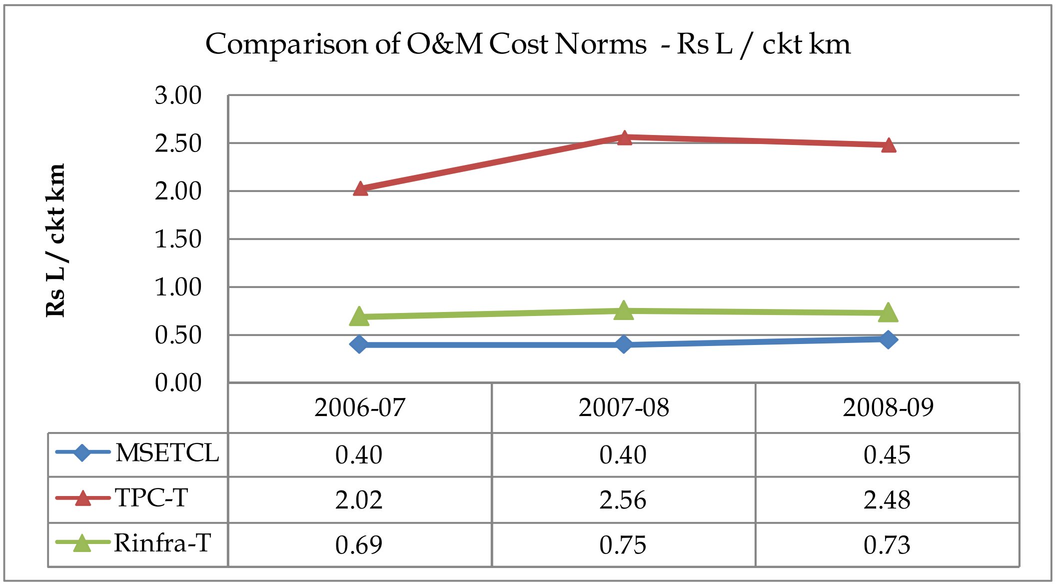
The above comparison shows that there exists significant difference in the network configuration of the three Utilities. The chart below compares the composition of O&M expenses of MSETCL, TPC-T and RInfra-T for FY 2007-08.

Comparison of O&M expense

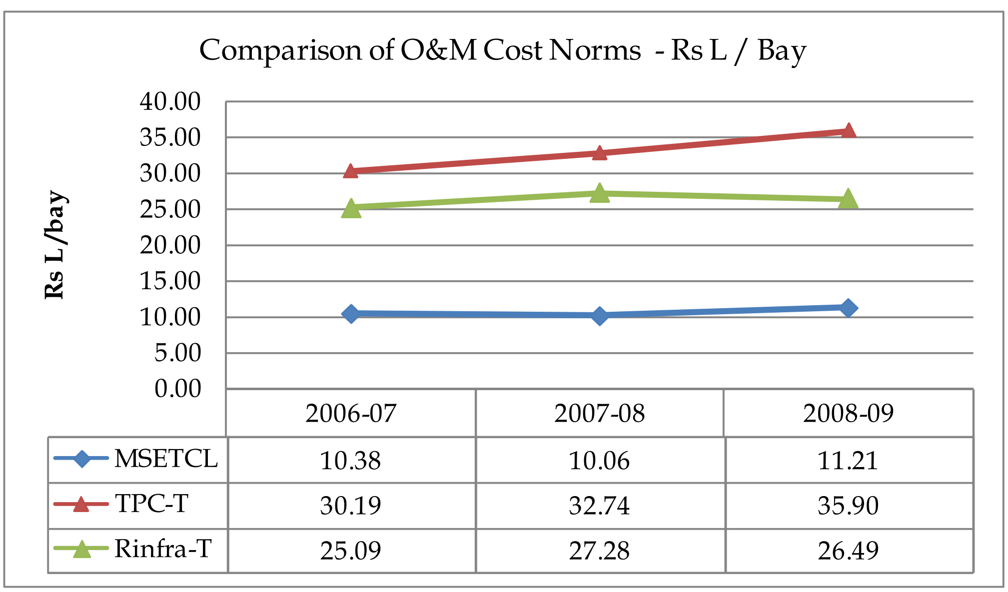


	MSETCL	TPC-T	RInfra-T
R&M Exp	165.35	8.98	2.49
A&G Exp	70.62	24.96	2.27
Employee Expenses	248.44	55.85	7.32

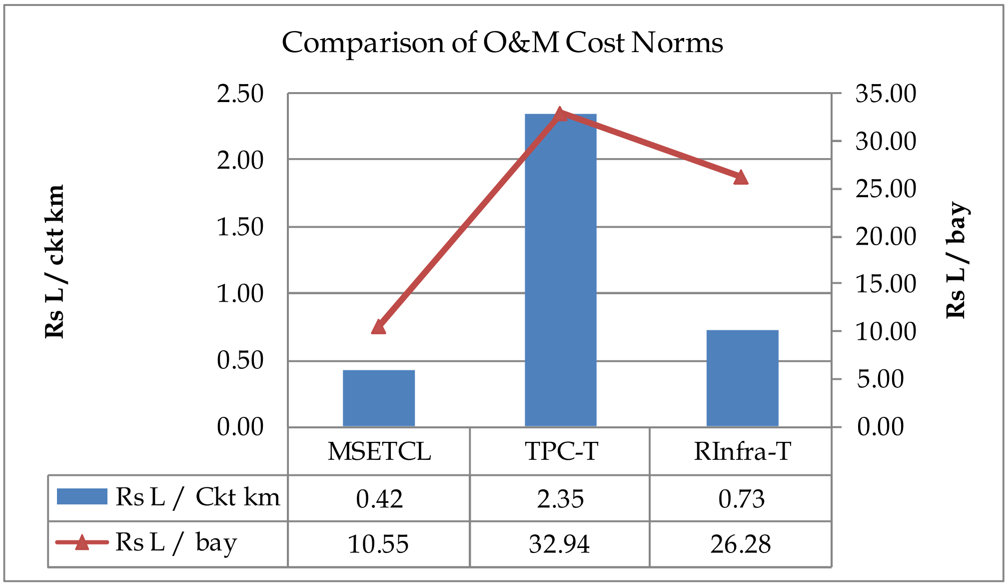
The chart below depicts the O&M expense norms based on Rs Lakh/ckt km and Rs lakh /bay for the Utilities. For comparison purposes, average expense norms for three years (FY 2006-07 to FY 2008-09) for each Utility have been considered.



The O&M expense norm linked to number of bays (no.) in respect of MSETCL, TPC-T and RInfra-T for the period from FY 2006-07 to FY 2008-09 is presented in the following chart:



The average norm (FY 2006-07 to FY 2008-09) for O&M expenses in terms of Rs L/ckt km and Rs L/Bay in respect of all the three transmission licensees, viz., MSETCL, TPC-T and RInfra-T, is presented in the following chart:



The main issue of discussion in the context of setting O&M norms would be whether to set individual Utility specific norms or a common norm for MSETCL, TPC-T and RInfra-T. From the above comparison, it is evident that the three transmission licensees within the State of Maharashtra differ significantly in their characteristics and setting a single norm for all the three Utilities may not be a practical option.

<u>Comparison of O&M expenses of the Intra-State Transmission licensees in Maharashtra with that of CTU (PGCIL)/CERC norms</u>

CERC in its Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009 notified on January 19, 2009 has specified the norms for O&M expenses for Transmission Licensees handling Inter State Transmission of power. CERC has specified voltage wise norms and separate norms for line assets and substation assets. The O&M norm specified by CERC is reproduced below:

Norms for O&M expenditure for Transmission System

	2009-10	2010-11	2011-12	2012-13	2013-14
Norms for sub-station (Rs Lakh per bay)					
765 kV	73.36	77.56	81.99	86.68	91.64
400 kV	52.40	55.40	58.57	61.92	65.46
220 kV	36.68	38.78	41.00	43.34	45.82
132 kV and below	26.20	27.70	29.28	30.96	32.73
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled conductor with four or more sub-conductors)	0.537	0.568	0.600	0.635	0.671
Single Circuit (Twin & Triple Conductor)	0.358	0.378	0.400	0.423	0.447
Single Circuit (Single Conductor)	0.179	0.189	0.200	0.212	0.224
Double Circuit (Bundled conductor with four or more sub-conductors)	0.940	0.994	1.051	1.111	1.174
Double Circuit (Twin & Triple Conductor)	0.627	0.663	0.701	0.741	0.783
Double Circuit (Single Conductor)	0.269	0.284	0.301	0.318	0.336
Norm for HVDC Stations					
HVDC Back-to-back stations (Rs lakh per 500 MW)	443.00	468.00	495.00	523.00	553.00
Rihand-Dadri HVDC bipole scheme (Rs Lakh)	1450.00	1533.00	1621.00	1713.00	1811.00
Talcher-Kolar HVDC bipole scheme (Rs Lakh)	1699.00	1796.00	1899.00	2008.00	2122.00

The total allowable operation and maintenance expenses for the transmission system is to be calculated by multiplying the number of bays and kms of line length with the applicable norms for the operation and maintenance expenses per bay and per km respectively.

It can be noticed that CERC has specified the transmission length based norm on per km basis rather than on the basis of per ckt km, since it has stipulated separate norms for single circuit line as well as double circuit lines. Further, CERC has made distinction in terms of type of conductor as well. However, while comparing the per ckt km norm and the per bay norm of CERC with that derived for Transmission Licensees, which form a part of the Intra-State Transmission system of Maharashtra, it is seen that CERC norms in terms of Rs Lakh/bay are significantly higher than that derived in case of the State transmission network.

5.4.2.3 Proposed formulation of O&M norms

Based on the analysis presented under earlier paragraphs, it is proposed to derive separate norms for each transmission licensee to address characteristic features and historical developments of transmission network and operating structure of these transmission licensees. The norm for the next Control Period has been derived based on the average of the norms for the period from FY 2006-07 to FY 2008-09 in terms of Rs Lakh/ckt km and Rs Lakh/bay in respect of these transmission licensees. The average norm so derived may be escalated linked to suitable inflation indices comprising weighted average of wholesale price index (WPI) and consumer price index (CPI). Such escalation factor may be applied for 2 years to derive applicable O&M norm for FY 2010-11 (i.e., first year of the next Control Period).

Accordingly, the O&M norm proposed for MSETCL, TPC-T, and RInfra-T for the next Control Period is as under:

O&M Expense Norm linked to transmission line length (ckt-km) shall be as under:

Rs L/ckt km	2006-07	2007-08	2008-09	Average	Inflation factor	Esclation factor	Proposed Norm (Rs L/ckt km)
MSETCL	0.40	0.40	0.45	0.42	5.72% for 2 yrs	1.12	0.47
TPC-T	2.02	2.56	2.48	2.35	5.72% for 2 yrs	1.12	2.63
Rinfra-T	0.69	0.75	0.73	0.73	5.72% for 2 yrs	1.12	0.81

O&M Expense Norm linked to number of bays (no.) shall be as under:

Rs L/bay	2006-07	2007-08	2008-09	Average	Inflation factor	Esclation factor	Proposed Norm (Rs L/ckt km)
MSETCL	10.38	10.06	11.21	10.55	5.72% for 2 yrs	1.12	11.79
TPC-T	30.19	32.74	35.90	32.94	5.72% for 2 yrs	1.12	36.82
Rinfra-T	25.09	27.28	26.49	26.28	5.72% for 2 yrs	1.12	29.38

The norms for any other transmission licensee shall be same as that determined for MSETCL.

The normative O&M expenses for each subsequent year of the Control Period shall be escalated at the inflation rate linked to wholesale price index (WPI) to arrive at permissible O&M Costs for the Control Period. These values would be reviewed as part of the Annual Performance Review in terms of efficiency factors.

5.4.3 Regulating performance of Competitively awarded Transmission Licences

The Electricity Act, 2003 envisages competition in transmission and has provisions for grant of transmission licenses by the Central Electricity Regulatory Commission (CERC) as well as State Electricity Regulatory Commissions (SERCs).

The National Electricity Policy notified on 12th February, 2005 inter-alia states that –

> *"5.3.1 The Transmission System requires adequate and timely investments and also efficient and coordinated action to develop a robust and integrated power system for the country.*
>
> *5.3.2 Keeping in view the massive increase planned in generation and also for development of power market, there is need for adequately augmenting transmission capacity………..*
>
> *5.3.10 Special mechanisms would be created to encourage private investment in transmission sector so that sufficient investments are made for achieving the objective of demand to be fully met by 2012.*
>
> *5.8.1 Considering the magnitude of the expansion of the sector required, a sizeable part of the investments will also need to be brought in from the private sector. The Act creates a conducive environment for investments in all segments of the industry, both for public sector and private sector, by removing barrier to entry in different segments. Section 63 of the Act provides for participation of suppliers on competitive basis in different segments which will further encourage private sector investment."*

Section 61 & 62 of the Act provide for tariff regulation and determination of tariff of generation, transmission, wheeling and retail sale of electricity by the Appropriate Commission. Section 63 of the Act states that –

"Notwithstanding anything contained in section 62, the Appropriate Commission shall adopt the tariff if such tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government."

In this context, the Commission shall adopt such tariffs as determined through transparent process of bidding in accordance with the guidelines issued by the Central Government. However, the successful bidder/developer should obtain a transmission licence from the Commission as stipulated in the competitive guidelines.

> *20. Along with the recommendation of selection by the Bid Evaluation Committee, **the selected developer shall approach the Appropriate Commission, within a period of 30 days, for grant of transmission license**. If it fails to apply for license within thirty days then it will be liable for cancellation of its selection. Cancellation of selection as provided above will be done by the Empowered Committee only after giving the selected private company an opportunity to be heard.*

Such a developer selected through a transparent competitive bidding process with a transmission License must submit its quoted Transmission Service Charge (TSC) to the Commission. The Commission shall adopt such TSC and pool the TSC along with the ARR of other transmission licensees which constitute the InSTS to form the Total Transmission System Cost (TTSC). The Transmission Service Charges and ARR of all transmission licensees would be recovered from the beneficiaries/transmission system users (TSUs) as part of the Transmission Tariff and shall be paid to the Licensee through the existing mechanism and settled for each payment period (not exceeding month).

5.5 *Regulating Transmission System Users/Usage (TSUs)*

The existing Transmission Pricing framework was introduced within Maharashtra through Commission's Order (Case 58 of 2005) dated June 27, 2006 and the same has been under operation over past three years. Further, CERC has recently initiated process for review of Transmission Pricing framework for inter-State transmission system, which is still under finalisation. As per National Tariff Policy framework, upon finalisation of such transmission pricing mechanism at regional level, the same could be evaluated for introduction at State level upon detailed analysis through Forum of Regulators. The preparatory work necessary for introduction of such framework has already been deliberated under earlier sections. Thus, existing transmission pricing framework may need to be continued for some time upon addressing some of the operational issues or emergence of new issues due to recent regulatory and market developments such as collective transactions through power exchange, introduction of medium term access at regional level, emergence of new private transmission licensees, operationalisation of competitive bidding framework for private sector participation in transmission etc. which has come into effect since introduction of earlier Transmission pricing Framework. Thus, following issues have been identified which needs to be addressed:

- How should transmission system usage be defined and monitored in case of usage by various transmission system users (TSUs)?
- Whether distinction in transmission pricing be made depending on tenure of usage (long term/medium term/short term)?
- Whether distinction should be made in case of renewable energy transactions entailing transmission system use?
- What should be the mechanism for recovery for usage of intra-State transmission system for inter-State wheeling transactions?
- What should be the principles for treatment of transmission losses?
- Should the existing principles for Transmission pricing based on co-incident peak demand, denominations, recovery etc. be modified?

5.5.1 Transmission System Usage : Nature & Tenure of Agreement

The key issue that need to be addressed is whether distinction for the purpose of revenue recovery should be made amongst long-term consumers and short-term consumers and if yes, to what extent. In this context, it is noted that, MERC (Transmission Open access) Regulations 2005, do not distinguish the transactions in terms of tenure. In fact, various provisions under Transmission Open Access Regulations, pertaining to transmission capacity rights (TCRs), trading of TCRs, penalty for excess utilization of TCRs, surrendering in case of non-utilisation/part-utilisation of TCR advocate that there is no need for any distinction in terms of transmission charges on the basis of tenure of the agreement. The transmission capacity rights of new TSUs are ranked "parri-passu" with transmission capacity rights of existing TSUs without any discrimination in terms of allotment or curtailment priority.

CERC in its recently notified regulations for Open Access namely, (i) CERC (Grant of Connectivity, Long term access and Medium term Open access in inter-State transmission and related matters) Regulations, 2009 notified on August 7, 2009 and (ii) CERC (Open Access in inter-State Transmission)(Amendment) Regulations, 2009 notified on May 20, 2009 has clearly defined the terms of long term access, medium term access, short term access and have also outlined the rights/obligations in respect of each type of open access transactions for use of inter-State transmission system, as summarized below:

- **Long term access** : For period exceeding 12 years but not exceeding 25 years
- **Medium term access**: For period exceeding 3 months but not exceeding 3 years
- **Short term access**: For Period upto 1 month at one time

Further, curtailment, if necessary, due to congestion, the short term open access transactions shall be curtailed first, followed by medium term transactions followed by long term transactions. Amongst the particular category of customers, the curtailment shall be carried out on *pro-rata* basis. Further, within short term open access transactions, bilateral transactions shall be curtailed first followed by collective transactions through power exchange.

In terms of pricing philosophy, the transmission charges for short term transactions (i.e. bilateral and collective transactions through power exchange) have been denominated in Rs/MWh (per unit) basis.

Suggestion:

For the purpose of use of intra-State transmission system within Maharashtra, the open access transactions may be classified as under:

- **Long term access** : For period exceeding 7 years but not exceeding 25 years
- **Medium term access**: For period exceeding 1 year but not exceeding 7 years
- **Short term access**: For Period upto 1 year

Period of long term (exceeding 7 years) and medium term (upto 7 years) has been suggested, which shall be consistent with timelines outlined under competitive bidding guidelines for procurement of power. In case of congestion, the short term open access transactions shall be curtailed first followed by medium term, followed by long term. Amongst the particular category of customers, the curtailment shall be carried out on *pro-rata* basis subject to condition that the within a particular category, the transactions exceeding the schedule shall be curtailed first upto its schedule requirement before applying the rule of *'pro-rata'* curtailment.

In terms of pricing, no distinction in terms of long term, medium term or short term access has been proposed, which shall be consistent with MERC Transmission open access Regulations. However, the transactions for long term and medium term shall be denominated in Rs/kW/month whereas, the short term bilateral transactions may be denominated in Rs/MW/day derived from transmission tariff specified for long term/medium term access considering thirty (30) number of days per month. The transmission tariff for short term collective transactions through power exchange shall be denominated in Rs/kWh (per unit basis) considering energy units (MU) projected to be handled by the intra-State transmission system (InSTS) for the ensuing year.

In view of lower capacity utilization factors for renewable energy transactions and in order to simplify the process of energy accounting and billing for renewable energy transactions, Transmission Tariff for renewable energy transactions shall also be denominated in Rs/kWh (per unit basis) as derived for short term open access collective transactions. It is clarified that no distinction is made in terms of transmission tariff for long term or medium term or short term transactions, only denomination of the transmission tariff has been specified separately, in order to address the operational difficulties in accounting and billing for various open access transactions including renewable energy.

5.5.2 Treatment of Transmission Loss

In case of inter-State transmission networks, the transmission losses on 52-weekly average basis are borne by all the beneficiaries in proportion to the actual energy drawn by the beneficiaries during the assessment period. This method is simple, easy to understand and implement and energy accounting is also simplified. Similarly, the composite intra-State transmission losses in case of Maharashtra are also considered to be borne by all transmission system users on pro-rata basis based on their actual energy drawal. Thus, average transmission loss of 'Intra-State transmission system' to be borne by all Transmission System Users results in state-wide uniform transmission loss across all transactions of various Transmission System Users, irrespective of entry point and exit point.

However, there could be another method for recovery of transmission loss, namely, incremental loss recovery method, under which incremental energy losses due to a transaction can be assessed and apportioned to that transaction. Further, as per clause 7.2 of National Tariff Policy it would be desirable to move to a system of loss compensation based on incremental losses as present deficiencies in transmission capacities are overcome through network expansion. This method provides scientific basis and rational for recovery of transmission losses. However, as number of transactions under open access regime grows, it would become increasingly complex to deal with multiple transactions and energy accounting would be complicated.

However, CERC, in its Order dated March 28, 2008, regarding sharing of regional transmission charges and losses has preferred to continue with existing approach of recovery of average transmission loss on actuals across all transactions. The relevant extract of CERC Order is reproduced below:

"23. Judicious allocation of transmission losses is important on many counts, e.g. (i) as input for optimal dispatch, (ii) as a signal for siting of new generation and load, (iii) for equity between widely-spaced beneficiaries. Further, it has to be done for the total system in operation on date (without differentiating between the old and the new systems), for which power tracing appears to be the practical mechanism. Its introduction would also be a pre-requisite for implementation of incremental loss concept for short-term open access and for introducing locational bias in the frequency-linked UI rates, which have been proposed by the Commission. Hence, an urgency in the matter."

CERC further observed that it would therefore encourage/urge the RLDCs to start working seriously regarding exploring feasibility of deployment of incremental loss methodology through power tracing mechanisms, with the target date extended to 1.10.2008. Their progress shall be reviewed by the Commission in July 2008, to decide the actual implementation date.

In addition, under recent approach paper circulated by CERC for revision in Transmission Pricing has also stated that issue of 'treatment of loss' by way of incremental loss allocation etc. through power tracing technique or otherwise, is being dealt with as part of separate study. Outcome of such study for implementation at regional level is still awaited. As per clause 7.2 of the Tariff Policy, based on methodology to be devised by CERC in this regards for inter-State transmission, Forum of Regulators may evolve a similar approach for intra-State transmission. The relevant extract of National Tariff Policy is as under:

> *"Transactions should be charged on the basis of average losses arrived at after appropriately considering the distance and directional sensitivity, as applicable to relevant voltage level, on the transmission system. Based on the methodology laid down by the CERC in this regard for inter- state transmission, the Forum of Regulators may evolve a similar approach for intra-state transmission."*

In view of above, it is proposed to continue with existing approach of treatment of uniform transmission loss across the intra-State transmission system to be borne by all transmission system users in proportion to their actual drawal.

5.5.3 Transmission pricing methodology sensitive to Distance

The revenue requirement of the transmission licensee is clearly dependent on line length (ckt-km), as the investment, asset base, operation and maintenance costs are linked to line length to a great extent. Further, transmission losses are also dependent on the total line length covered by the network. Hence, it would be appropriate to link Transmission Charges to the line length (ckt-km) traversed.

Clause 5.3.4 of the National Electricity Policy notified by the Central Government has advocated that in order to facilitate cost effective transmission of power across the region, a national transmission tariff framework needs to be implemented by CERC by April 2006 and the same needs to be sensitive to distance, direction and related to quantum of flow. Further, the Tariff Policy notified by GoI has stated that in order to achieve consistency in approach within inter-State transmission system and intra-State transmission system, a similar approach should be implemented by SERCs in next two years after implementation of such framework for inter-State transmission system.

Presently, the intra State transmission pricing framework in the State of Maharashtra is based on a "Postage Stamp" approach which is inline with the existing CERC Regulations, which is insensitive to the distance but offering significant other advantages such as simplicity, ease in understanding/usage, and is also a time tested approach. However the same approach is not in accordance with NEP and NTP notified by the Central Government.

The CERC has recently come out with an approach paper on formulating pricing methodology for Inter State transmission, initiating the process of modifying the Regulations to make it in line with the requirements of NEP and NTP. The salient features of the approach paper are given below.

Pricing approaches considered in the Approach Paper

- **Marginal Participation Method**

- **Average Participation Method**
- **Zone-to-Zone Method**

(All three methods are based on load flow studies indicating the use of the system, but use different approaches for determining the use of the network by various users of the transmission system.)

Approach Recommended and its salient features

<u>Marginal Participation(MP) Method</u>

10. **Better economic and technical properties** as compared to other approaches
11. Transmission prices determined using MP method **measure how much each agent is benefiting** from the existence of various network facilities.
12. MP method **directly computes the relative use of each network branch** by generators and demand customers (The split of transmission charges between generators and demand customers needs to be specified by the user in other models). This **provides clear locational signals to generation and demand customers**.
13. The MP method **considers the meshed network as a common use facility**. **Utilization of the network branches as determined based on actual power flows** on the network. This obviates the need for arbitrary assumptions.
14. Transmission charges determined using MP method are **Point Tariffs**, indicating that each user of the network will be required to pay a **fixed charge depending on its location in the network**.
15. These charges are in Rs/MW/month depending on the location of generator / demand customer and **provide clear signals based on distance and direction**.
16. **Chargeable capacity**: determined based of forecast of generation level by generators and demand level by the demand customers. (Transmission charges indicated in Rs/MW/month are multiplied by the chargeable capacity to determine monthly charges.)
17. **Implementation of Point Tariffs**:

- Generators and demand customers will be required to sign alternate commercial agreements - **Connection and Use of System Agreement (CUSA)** (alternate to existing BPTA)
- Apart from the need for specifying the destination of power for a generator and the source of power for a demand user, **other key provisions of a BPTA would be retained** in the CUSA.
- The need for separate charges for long term and short term open access is obviated.

18. The **transmission tariffs so determined do not lead to pancaking** and hence send cost-reflective signals for efficient inter-state and inter-regional trading.
19. Proposed mechanism **considerably simplifies the allocation of transmission charges** between parties involved in electricity trades on the power exchange.

The generators selling power on the exchange can **internalize the transmission charges in their price bids**, whereas the demand customers can be charged transmission charges separately **based on short term access approved**.

This approach paper is under the discussion stage and CERC is yet to come out with the Regulation based on the recommendations of the paper. While formulating the new regulations in this matter, views of various stakeholders are also to be taken into consideration and the same process is currently underway.

The selection of distance sensitive approach would require careful evaluation of implications for various distribution companies (DISCOMs) on account of power flow from source (generating stations) to various regions.

Besides, as highlighted under earlier section, CERC has initiated process for review of Transmission Pricing framework for regional transmission system. The same may be evaluated by Forum of Regulators before introduction at State level, as per provisions of the National Tariff Policy.

Hence, at this stage, it may be preferable to continue uniform Postage Stamp approach across the State.

5.5.4 Transmission Price Components for Reactive energy drawal/injection linked to voltage profile

Reactive energy flows in the transmission network reduces the active power carrying capability of the system apart from increasing transmission losses and reducing voltage at the points of drawal. Reactive energy flows can be compensated by means of capacitor installations in the local networks.

Further, in the context of open access regime, reactive energy management by distribution companies (DISCOMs) would play a critical role in maintaining steady voltage profile of grid. Poor reactive energy management would result in sub-optimal utilization of transmission resources. Hence, pricing ('Tariff') for reactive energy drawal should be such that it provides stronger economic signal for better reactive power management by the TSUs (DISCOMs, or Transmission Open access Users). Appropriate incentive and penalty mechanism for reactive energy drawal/injection linked to voltage at inter-connection point should also be devised in order to encourage better demand side management practices.

As such, for the inter-State energy transactions, the associated reactive energy has not been assigned a price, but there is a scheme under IEGC, which penalizes reactive energy drawal and rewards reactive energy injection @ 5.25 paise/kVARh, when the voltage at the inter-State connection point is below 97% of nominal value. Similarly, the scheme penalizes reactive energy injection and rewards reactive energy drawal @ 5.25 paise/kVARh, when the voltage at the inter-State connection point is above 103% of nominal value. The reactive energy accounting is done by the RLDCs based on the readings of the Special Energy Meters (SEMs) installed at the point of interconnections over the inter-State transmission system.

In case of State level transmission network, implementation of transmission tariff component linked to reactive energy (consumption or injection) assumes significant dimension, since reactive power compensation and/or management is the responsibility of various stake-holders including generators, consumers as well as transmission licensees. In case of renewable energy generators, in the past, the Commission had directed them to generate reactive energy at least equivalent to 36% of active energy injected into the grid by them. In case of shortfall, the reactive energy compensation has been priced at Rs 0.25 per kVARh. However, the same cannot be readily applied for reactive energy compensation for the entire transmission system.

In fact, CERC in its Background Note for notification of IEGC has stated that SERCs will have to devise mechanism for Reactive Power management and compensation thereof, upon careful deliberation and taking into account State specific factors which could vary from State to State. Accordingly, CERC has recognized that approaches for reactive power management and compensation would vary. The relevant extract of the Background Note is as under:

> *"The intra-State scheme for pricing of reactive energy exchanges between the intra-State entities has to be very carefully deliberated upon by the concerned SERC/STU, and duly covered in the State Electricity Grid Code. The requirements of local reactive support may differ from State to State and the approach may differ from that in this IEGC. For example, the inter-State generating stations (ISGS) have to generate/absorb reactive power as per instructions of RLDC, "without sacrificing on the active generation required at that time", and "no payment shall be made to the generating companies for such VAr generation/absorption.*
>
> *This is because (1) the ISGS are mostly located away from load-centres, (2) they generally have a lower variable cost, and (3) they are paid a capacity charge covering the cost of entire installation, including their reactive power capability. The situation of intra-State stations may differ in these respects, and a different approach to their reactive energy output may be necessary."(emphasis added)*

In this context, it is also observed that as per Regulaiton 9.7 of the State Grid Code, STU should undertake planning studies to evaluate reactive power compensation requirement of the Grid.

> *"State Transmission Utility shall carry out planning studies for Reactive Power compensation of intra-State Transmission System including reactive power compensation at the in-State Generating Station's switchyard." (Clause 9.7 of State Grid Code Regulations)*

In view of the above, it is proposed that until State Transmission Utility undertakes planning studies for Reactive Power compensation of intra-State transmission system, reactive power injection and drawal shall be charged in accordance with following methodology, as an interim measure. Further, it is clarified that following mechanism can be implemented only after adequate metering, energy accounting and billing infrastructure covering all interchange points on the intra-State transmission system is put in place by STU and the concerned agencies, as may be applicable.

Party responsible for reactive energy compensation	**Threshold performance**	**Voltage at Inter-change point (V_p)**	**Rate for compensation**
Transmission Licensees	Permissible voltage variation as per IEGC/State Grid Code.	- If $V_p > 103\%$ of V_{nom} - If $V_p < 97\%$ of V_{nom} - If $97\% < V_p < 103\%$	- Penalty at the rate of Rs 0.25/RkVAh for additional injection. - Incentive at the rate of Rs 0.25/RkVAh for additional injection. - Nil
TSU (Distribution Licensee / OA Users directly connected to State transmission network)	Maximum reactive energy drawal at each interchange point to be limited corresponding to power factor of 0.9	- If $V_p > 103\%$ of V_{nom} - If $V_p < 97\%$ of V_{nom} - If $97\% < V_p < 103\%$	- Incentive at the rate of Rs 0.25/RkVAh for additional drawal. - Penalty at the rate of Rs 0.25/RVkAh for additional drawal. - Nil

Above scheme can be extended to open access customers who are directly connected to the State network.

5.5.5 Pricing Incentives linked to performance.

Norms of Operation: Fixed Cost Recovery

The existing MERC Tariff Regulation, 2005, provides full recovery of Annual Transmission Charges on the basis of annual availability of the Transmission network system of the transmission companies. The Commission has set norms for both HVDC and HVAC system availability. The provision is as below.

> *"Target availability for full recovery of annual transmission charges*
>
> *(a) AC system :- 98 per cent*
>
> *(b) HVDC bi-pole links and HVDC back-to-back stations :- 95 per cent*
>
> *Recovery of annual transmission charges below the level of target availability shall be on pro rata basis. At zero availability, no transmission charges shall be payable.*

Further, the Commission in its Order Case No. 58 of 2005 had ruled as under:

> *"2.8.7 Accordingly, the Commission rules that the transmission licensee shall be entitled to incentive on achieving annual availability beyond the target availability as stipulated under MERC (Terms and Conditions for Tariff) Regulations 2005, in accordance with the following formula:*
>
> *Incentive = Annual Transmission Charges x [Annual availability achieved – Target Availability] / Target Availability;*
>
> *Where,*
>
> *Annual transmission Charges shall correspond to ARR for the particular transmission licensee within State, as the case may be.*
>
> *Provided that no incentive shall be payable above the availability of 99.75% for AC system and 98.5% for HVDC system."*

Further, CERC, in its Terms and Conditions for Tariff Regulations 2009, has specified a reduced availability norm of 92% for HVDC bi-pole links. Past performance of the transmission licensees (for FY 2007-08) in terms of Transmission system availability and incentives earned is summarised below:

Particulars (for FY 2007-08)	**Availability (%)**	**Incentives (Rs Crore)**
HVAC		
- MSETCL	98.99%	13.10
- TPC-T	99.46%	2.99
- RInfra-T	99.44%	0.71
HVDC		
- MSETCL	92.28%	(6.53)

The issue to be addressed in this case are:

- Whether target availability norm for HVAC and HVDC should be revised for the next Control Period? To what extent?
- Whether incentive structure formulation be modified?
- Whether voltage-wise monitoring of transmission system availability be undertaken and whether incentive/dis-incentive structure be operationalised at each voltage level?

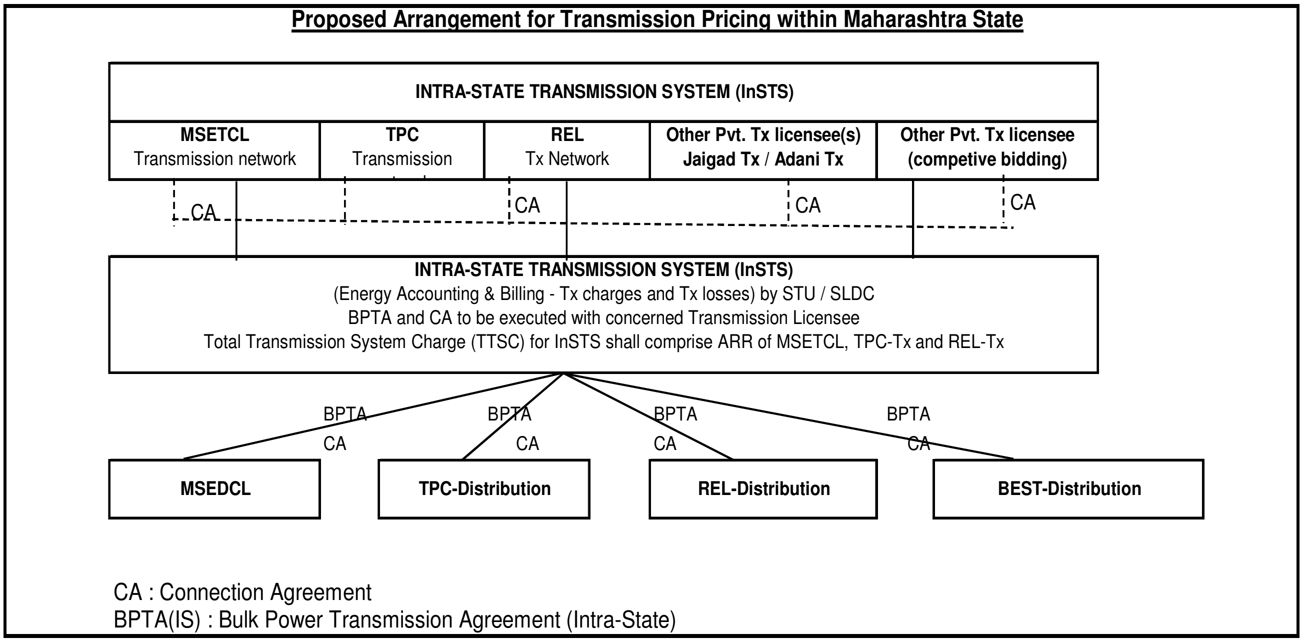
Further in this context, it is proposed that transmission system availability of the transmission licensee needs to be certified by Maharashtra State Load Despatch Centre (MSLDC). Accordingly, the MSLDC should formulate appropriate procedure to monitor and certify the Transmission System Availability of various transmission licensees on regular basis.

<u>Incentives/Dis-incentives for transmission loss reduction:</u>

Apart from Target Availability for recovery of fixed cost, it is also proposed to devise a mechanism in order to incentivise the transmission licensees who achieve the transmission loss reduction target as approved by the Commission in the respective Transmission utility's Comprehensive Business Plan for loss reduction in a Financial Year for which the annual transmission charges are determined. The computation of incentives/dis-incentives for excess or shortfall in achievement of target loss reduction applicable to transmission licensees may be denominated in paise/kWh (say, 5-10 paise/kWh). For example, as against target reduction of transmission loss by 0.5%, transmission licensee achieves reduction by 0.6%, transmission licensee shall be entitled for excess reduction of 0.1% at 5 paise/kWh on additional reduction of transmission loss units. For transmission utility with energy units handled upto 1,00,000 MU, 0.1% excess reduction shall translate to 100 MU and incentive of Rs 5 Million at incentive rate of 5 paise/kWh. Similarly, dis-incentives for shortfall vis-à-vis target loss reduction shall also be applicable. Feasibility of such an incentive mechanism would depend greatly on the availability of data and accurate ascertainment of transmission losses of each utility, and such information would be available once the ongoing interface metering is completed.

5.5.6 Proposed Mechanism for Intra-State Transmission Pricing

In the State of Maharashtra, the recovery of ARR of transmission utilities or Transmission Service Charge (TSC) in case of competitively awarded transmission projects, as the case may be, shall be based on a 'pooled cost' principle wherein the ARR/TSC of all the transmission Utilities will be pooled together and shared among the transmission system users (Distribution licensees) based on their share in the coincident peak demand of the State. The block diagram shown below depicts the existing mechanism for recovery of ARR within the State of Maharashtra.



The salient features of the proposed arrangement of 'Transmission Pricing' of Intra State Transmission System (InSTS) are as under.

a) Intra-State transmission system comprise composite transmission network of MSETCL, TPC, RInfra, Jaigad Power Transco, Adani Power Transmission Co. and any other private transmission licensee in future.

b) Each transmission licensee including existing transmission licensees (i.e. MSETCL, TPC, RInfra, Jaigad, Adani) shall submit its ARR Petition to the Commission in accordance with the Tariff Regulations and seek its approval or seek adoption of TSC in case of competitively awarded transmission system component, as the case may be.

c) Aggregate of Annual Revenue Requirement of all licensees, as approved by the Commission, shall form the "Pooled Cost" (or hereinafter termed as "Total Transmission System Cost – TTSC) of the intra-State transmission system, to be recovered from the Transmission System Users (TSUs).

d) The revenue from collective transactions over power exchange and short term bilateral transactions shall be used to reduce TTSC for long term/medium term transactions.

e) The Commission shall approve ‘Base Transmission Capacity Rights’ for measuring the “Capacity Utilisation’ of intra-transmission system and accordingly determine “Base Transmission Tariff” for the same.

f) ‘Base Transmission Tariff’ for each financial year is derived as ‘TTSC’ of intra-State transmission system divided by ‘Base Transmission Capacity Rights’ and denominated in terms of “Rs/kW/month” (for long term/medium term) or “Rs/MW/day ” (for short term bilateral transactions) or “Rs/kWh” (for collective transactions over power exchange).

g) Each distribution licensee and transmission open access user (TSU) having connection with the “intra-State Transmission system” shall enter into Bulk Power Transmission Agreement (BPTA) and Connection Agreement with concerned transmission licensee. The STU, in turn, enter into contracts with various transmission licensees within the State for usage of their transmission system.

h) MSETCL, in its capacity as STU and as Government Company operating the SLDC, is responsible for undertaking recording of state-wide energy accounts, monitoring power flows and recording utilization of capacity across intra-State transmission system.

i) Each TSU (distribution licensee or Transmission OA User), shall be required to pay intra-State transmission system charges (i.e. Transmission Tariff) at the approved rate of “Base Transmission Tariff” corresponding to its utilization of ‘intra-State transmission’ capacity.

j) Each transmission licensee shall be entitled to recover its approved ARR or TSC as the case may be, from Intra-State Transmission system charges (InSTS charges) collected by STU.

k) The proposed arrangement for ‘Transmission Pricing’ is scalable in the sense that, as the system of metering, energy accounting and billing evolves, and power flows across intra-State transmission system can be monitored more accurately from instant to instant, the ‘Base Transmission Capacity Rights’ can be modified to adopt ‘MW-mile’ method for charging the ‘Transmission Tariff’.

l) Besides, future addition to transmission capacity (in accordance with the approved Transmission Plan) within the State can be undertaken by STU or existing other transmission licensee or any other new transmission licensee. The ARR pertaining to such transmission capacity addition shall form part of overall

'TTSC' of intra-State transmission system (For example, ARR of recently awarded transmission licensees - Jaigad Power Transmission Company and Adani Transmission Company).

m) The competitive bidding guidelines for procurement of transmission capacity additions can be easily adopted for future capacity addition programme without modification to 'Transmission Tariff' framework.

SLDC shall continue to undertake State-wide energy accounting and determination of transmission losses for intra-State transmission system.

5.5.7 Design Issues related to Transmission Pricing

The revenue requirement of the Transmission Licensee is envisaged to be recovered by way of levy of Transmission Tariff on the customers. In the context of Transmission pricing framework for recovery of ARR, the following issues need to be addressed:

- Issue-1: Charge linked to energy drawal and/or energy injection depending on nature and type of Customers (Licensees, Generating Companies, Open Access consumers)
- Issue-2: Charges for Use of network and/or Access of network
- Issue-3: Charge linked to Capacity (kW) or Quantum of energy (kWh)
- Issue-4 : Transmission Tariff components and design basis

5.5.7.1 Issue-1: Charge linked to energy drawal and/or energy injection

The Transmission Licensee, as a wire company acts as service provider and hence its customers could comprise distribution licenses, generating companies including captive generators, trading licensees and open access consumers as and when open access is enabled for various categories in accordance with the Open Access Regulations. Section 39(2)(d) of the EA 2003 provides for payment of Transmission Charges by all the above categories for use of the transmission network.

Earlier, CERC in its Regulations for Open Access for the purpose of inter-State transmission using CTU network, has adopted an approach such that Transmission Charges are recovered from beneficiaries/off-takers including open access consumers and not from generating companies.

However, it is envisaged that generating companies located within State would be required to use STU (MSETCL) network for wheeling power within as well as outside of State under open access regime. Further, as generation capacity within the State is expanded either through State/Private parties in order to exploit available natural resources and wheel power to/ from other States, there would be a requirement for MSETCL as STU to expand/augment transmission network and provide evacuation facilities to such generating companies. In case, 'transmission tariff' is devised such that the recovery is linked only to "drawal" within State and not linked to 'injection', the Transmission System Users within State would be required to bear cost of transmission facilities (evacuation facilities) created mainly for wheeling power outside the State.

Hence, it is critical to determine whether recovery of annual revenue requirement (or Total Transmission System Cost - TTSC) of other transmission licensees within State and the corresponding design of Transmission Tariff should be linked to only drawal of power and/or linked to injection of power as well. One option is to charge the generating companies for injection of energy and use of transmission network only if they seek open access for supply to captive consumers or for sale to consumers / licensees outside the State. In all other cases, where generating companies are using transmission network for supplying power within the State, the transmission charges shall be recovered only from distribution licensees and transmission system users.

Suggestion:

It is proposed that the long term transmission tariff shall be linked to 'drawal' to be recovered from the transmission system users such as distribution licensees and open access users within State. However, in case transmission system is used by generators for wheeling power outside the State, the same shall be recovered from generators to the extent of 'injections' or contracted capacity used for wheeling power outside State.

5.5.7.2 Issue-2: Charges for Use of network and/or Access of network

As stated earlier, the entire grid network assets can be classified into Core Grid Assets and Connection Assets and the revenue requirement of these can be determined separately.

The Transmission Tariff can thus, be structured on two part basis, viz., (a) Network Access Charge, representing revenue requirement corresponding to Connection Assets for access of network from respective consumers, including all Generating Companies, on pro-rata basis; (b) Network Use Charge, representing revenue requirement corresponding to Core Grid Assets for use of network from all customers based on usage linked to capacity (kW) or units handled (kWh).

However, separation of revenue requirement and assets into Connection Assets and Core Grid Assets is a rigorous and intensive process and would be difficult unless appropriate accounting systems are adopted. Until accounting systems are put in place, apportionment or allocation of costs amongst connection assets and Grid assets based on technical information can be adopted.

Under the MYT framework, the Transmission Utilities may be directed to separate account related information pertaining to Connection Assets and Core Grid Assets and the Revenue Requirement for Transmission Utilities within Maharashtra could be apportioned between Connection Assets and Core Grid Assets for the purpose of determination of Transmission Tariff in terms of Connection Charge and Access Charge, separately.

5.5.7.3 Issue-3: Charge linked to Capacity (kW) or Quantum of energy (kWh)

The Transmission Tariff can be designed such that recovery of revenue requirement is linked to usage in terms of either Capacity (kW) or Units (kWh).

In case of inter-State transmission network of CTU, prior to implementation of Availability Based Tariff (ABT) regime, the transmission charge recovery was linked to drawal of energy units (kWh) by the beneficiary on pro-rata basis. However, subsequent to implementation of ABT in all the regions, the recovery of Transmission charges and revenue requirement is linked to capacity allocation amongst the beneficiaries. The capacity allocation includes allocation of inter-State Generating Stations (ISGS) as well as capacity tied through bilateral contracts.

Recently, with amendment to short term Open Access Regulations, particularly to deal with issues of collective transactions over power exchanges, CERC has once again introduced the concept of transmission charges based on energy units (kWh), albeit, for the purpose of short term OA transactions alone. Linking the recovery of ARR to energy units transmitted and denominating the Transmission Tariff in Rs/kWh would provide a mechanism that would be very simple to understand and easy to implement. However, the same may expose the transmission licensee to risk of under-recovery of transmission charges in case actual energy units handled by transmission licensee are lower than the base energy units assumed to be handled by transmission system for the purpose of determination of Transmission Tariff.

On the other hand, in case actual energy units handled by transmission licensee are more than base energy units assumed, it would lead to over-recovery of transmission charges necessitating Transmission System User (TSUs) to pay excess transmission charges than that required to meet revenue requirement of transmission licensee. Moreover, transmission tariff mechanism linked to energy units may not be consistent with the Transmission Pricing mechanism adopted at regional level.

Suggestion

It is proposed to specify Transmission Tariff as under:

a) For Long term and medium term transactions: in terms of Rs/kW/month
b) For short term bilateral transactions: in terms of Rs/MW/day
c) For collective transactions over power exchange and renewable energy transactions: in terms of Rs/kWh

5.5.7.4 Issue-4: Transmission Tariff Components and Design Basis

A transmission licensee may be allowed to recover his revenue requirement of transmission charges as one or combination of the following charges:

(i) Network Access charge - A fixed charge corresponding to cost recovery for Connection Assets.

(ii) Network Usage charge - A fixed charge (in Rs. per KW per month) based on capacity contracted or allotted

(iii) A charge based on energy transmitted

(iv) Connectivity charge.

(v) Reactive energy charge.

While selecting the parameter for recovery, i.e., capacity (kW) or energy units (kWh), it should be noted that significant component of transmission costs are fixed in nature. Further, transmission charges should be denominated in units in which these have been defined under Open Access Regulations, i.e., capacity in MW or kW. It will not be possible to define transmission charge in Rs/kWh while trading of Transmission Capacity Rights is to be carried out on MW basis as envisaged under the Open Access Regulations.

The advantage of linking recovery to capacity is that it provides the right commercial signal to users for contracting/blocking the available transmission capacity only if it is required for use. In addition, basis for capacity parameter can be devised around (a) capacity usage based on installed generation capacity and contracted capacity, or (b) capacity usage based on System Maximum Demand (SMD)/contribution to co-incident peak demand (CPD), or (c) capacity usage based on non-coincident peak demand (NCPD) or (d) Actual system demand.

There exist various alternatives for Transmission Tariff Design based on denomination of Transmission Capacity Rights depending on modality of capacity allocation as outlined below.

1) **Sharing based on Contracted Capacity**

Share of Installed Generation Capacity (Alternative-1A)

Contribution to Co-incident Peak Demand (CPD) (Alternative-1B)

Share based on Non-coincident Peak Demand (NCPD) (Alternative-1C)

The principles, key considerations and the concerns thereof, for devising Transmission Tariff under each of the above alternatives have been discussed briefly in the following table:

Method for Transmission Tariff Design	**Principle**	**Key Considerations and Concerns**
Alternative-1A: Share of installed generation capacity of TSU (Licensee/TOA User)	Under this approach, the annual transmission charges shall be shared amongst the transmission system users based on their share in generation capacity (installed and contracted for procurement) within State.	o Typically, within network at State level, ratio of peak demand met and the installed capacity of generating stations (comprising significant hydel potential) is low on account of several factors such as availability of generating stations, seasonality factors, etc. Thus, the transmission capacity utilisation factor in case of distribution companies is low, as compared to any other TSU (e.g. OA user). o Lack of flexibility on the part of the Discom to modify its share in the transmission cost if its consumption within its area reduces for any reason. o Transmission charges not reflective of the co-incident or non co-incident peak
Alternative-1B: Contribution to	Under this approach, the annual transmission charges	o This approach is in line with the approach for determining the Cost

Method for Transmission Tariff Design	**Principle**	**Key Considerations and Concerns**
Co-incident Peak Demand (CPD)	shall be shared amongst the transmission system users based on their contribution to system maximum demand or co-incident peak demand (CPD).	of Service for determining the actual cost involved in servicing the consumers. o The Discom, as a demand-aggregator, would benefit from the diversity of consumer mix which would result in a gap between the non-coincident peak and the coincident peak and therefore, the Discom would incur a lower transmission cost. o This approach is data intensive and dependent on assumptions of co-incident factors. Availability of data/information pertaining to system demand is critical for adoption of this approach.
Alternative-1C: Share based on Non-coincident Peak Demand (NCPD)	Under this approach, the annual transmission charges shall be shared amongst the transmission system users based on their share in Non-coincident peak demand (NCPD).	o Under this approach, Discoms are expected to base their contract demand on their expected non-coincident peak for the year. o Under this approach sharing of transmission costs would reflect peak utilisation of each TSU at different points in time.

<u>Suggestion:</u>

For the next Control Period, it is proposed to continue with the existing practice of determining Transmission Tariff based on share or contribution of TSUs towards 'Co-incident peak' demand based on co-incident peak demand recorded in the previous year.

6 Norms and Principles for Determination of Wheeling Charges for Wires Business

The distribution licensees in the State of Maharashtra receive electricity at the Transmission to Distribution (T< >D) interface points through the Intra-State Transmission System (InSTS). From the T< >D interface, the electricity is distributed to the individual consumers' premises using the distribution network. The business of owning and operating the distribution network is called as the Wires Business, as distinct from the Retail Supply Business, which has a contract with the consumer for supply of electricity and enters into long-term and short-term power purchase contracts for the required quantum of electricity. The Aggregate Revenue Requirement of the Wires Business is recovered through the wheeling charges of the Distribution Licensee and shall comprise the following:

a) Return on Capital Employed: General principles have already been discussed earlier in Section-3 of this Approach Paper;

b) Depreciation: General principles have already been discussed earlier in Section-3 of this Approach Paper;

c) Operation and maintenance expenses;

d) Interest on working capital and deposits from Distribution System Users: General principles have already been discussed earlier in Section-3 of this Approach Paper;

e) Contribution to contingency reserves: General principles have already been discussed earlier in Section-3 of this Approach Paper.

Wheeling charges = Aggregate Revenue Requirement, as computed above, minus:

f) Non-tariff income; and

g) Income from Other Business.

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6.1 Separation of Accounts for Wire related and Retail Supply related business

Section 62 of the EA 2003 requires the State Electricity Regulatory Commission (SERC) to determine the tariff for Wheeling and Retail supply of electricity. Section 42 of the EA 2003 requires the SERC to introduce open access in the distribution system in a phased manner and stipulates that the duties of the distribution licensee with respect to such supply shall be of a common carrier providing non-discriminatory open access. Also, under Section 9 of the EA 2003, captive consumers are required to pay wheeling charges for availing open access, and are exempted from payment of cross-subsidy surcharge and additional surcharge. Therefore, wheeling charges are to be paid by any person for availing open access using the distribution licensee's network.

The Commission, in its various Tariff Orders for distribution licensees, has directed the distribution licensees to separate the accounting of network related costs and supply related costs, which is essential for un-bundling of cost and tariff components and forms a pre-requisite for appropriate determination of wheeling charges and affects open access transactions as mandated under the EA 2003. The need for segregation of network costs in terms of voltage level (HT and LT level) has also been emphasised.

The existing MERC Tariff Regulations also stipulate that the distribution licensees should maintain separate records for Distribution (Wire) Business, as reproduced below:

> *"55 Separation of accounts*
>
> *55.1 Every Distribution Licensee shall make a separate application for determination of tariff for-*
>
> > *(a) Wheeling of electricity;*
> >
> > *(b) Retail sale of electricity:*
>
> *Provided that every Distribution Licensee shall maintain separate records for the Distribution Business and shall prepare an Allocation Statement to enable the Commission determine the tariff pursuant to each such application made by the Distribution Licensee."*

However, none of the distribution licensees has compiled with the above Regulation. While RInfra-D submits separate Formats for the Wire Business and Retail Supply Business, MSEDCL and TPC-D have used some assumption/method for allocation of expenses between the Wires and Retail Supply business, in their respective Tariff Petitions. However, BEST has sought exemption from the open access provisions of the EA 2003, which states:

> *"42. (1) It shall be the duty of a distribution licensee to develop and maintain an efficient, co-ordinated and economical distribution system in his area of supply and to supply electricity in accordance with the provisions contained in this Act.*
>
> *(2) The State Commission **shall introduce open access in such phases** and subject to such conditions, (including the cross subsidies, and other operational constraints) as may be specified within one year of the appointed date by it and **in specifying the extent of open access in successive phases and in determining the charges for wheeling,** it shall have due regard to all relevant factors including such cross subsidies, and other operational constraints:*
>
> *......*
>
> *(3) Where any person, whose premises are situated within the area of supply of a distribution licensee, **(not being a local authority engaged in the business of distribution of electricity before the appointed date)** requires a supply of electricity from a generating company or any licensee other than such distribution licensee, such person may, by notice, require the distribution licensee for wheeling such electricity in accordance with regulations made by the State Commission and the duties of the distribution licensee with respect to such supply shall be of a common carrier providing non-discriminatory open access .*
>
> *51. (1) A distribution licensee may, with prior intimation to the Appropriate Commission, engage in any other business for optimum utilisation of its assets:*
>
> *Provided that a proportion of the revenues derived from such business shall, as may be specified by the concerned State Commission, be utilised for reducing its charges for wheeling:*
>
> *Provided further that the distribution licensee shall maintain separate accounts for each such business undertaking to ensure that distribution business neither subsidies in any way such business undertaking nor encumbers its distribution assets in any way to support such business.*

*Provided also that **nothing contained in this section shall apply to a local authority engaged**, before the commencement of this Act, in the business of distribution of electricity."(**emphasis added**)*

Hence, BEST has contended that being a local authority, it is exempted from providing Open Access to consumers within its distribution licence area, and hence, there is no need for separation of Wires and Supply business, as well as determination of wheeling charges in case of BEST. Accordingly, the Commission has not been determining Wheeling Charges for BEST, while issuing the Tariff Orders for BEST.

On August 20, 2008, the Commission notified the MERC (Specific Conditions of Distribution Licence applicable to The Tata Power Company Limited) Regulations, 2008, effectively confirming TPC-D as a distribution licensee in the entire city of Mumbai covering the licence areas of both BEST and RInfra-D. TPC-D's distribution licence is valid upto August 15, 2014. This is possibly one of the first instances of a parallel distribution licensee being in existence anywhere in the country. Thus, neither RInfra-D nor BEST have a monopoly distribution licence in their respective licence areas.

In the context of migration of consumers from one supply licensee to another, getting supply by utilisation of the wires laid down by one of the distribution licensees is an option to the approach of incurring heavy capital expenditure for the network roll-out, and the provisions of the EA 2003 relating to Open Access and the provisions of the MERC (General Conditions of Distribution Licence) Regulations, 2006 relating to use of the distribution network of another distribution licensee, need to be explored by TPC-D, so that the cost is optimised.

The MERC (General Conditions of Distribution Licence) Regulations, 2006, specify as under:

"8.3.5 The Distribution Licensee shall provide "Non discriminatory Open Access" to the Distribution System (for wheeling of electricity) for use by any Licensee, Generating Companies including Captive Generating Plants or Consumers in accordance with the Regulations made by the Commission for the purpose.

8.3.6 The Distribution Licensee shall provide to other licensees the intervening distribution facilities to the extent of surplus capacity available, in his Distribution System in accordance with the Regulations made by the Commission for the purpose or as directed by the Commission and in the event of any dispute as to the availability of the surplus capacity the same shall be determined by the Commission. The charges, terms

> *and conditions for the use of the intervening facilities may be mutually agreed between the Licensees subject to any order made by the Commission for the purpose."*

All consumers in RInfra-D and BEST licence area, irrespective of load and consumption, are entitled to apply for supply from TPC-D. Hence, it is necessary for the Commission to determine the wheeling charges and wheeling losses in BEST licence area also, to facilitate retail supply competition in BEST licence area also, as envisaged under the EA 2003.

Today, the problem is arising because the wire business and supply business are operating in an integrated manner, with the same entity having the distribution and supply licence. It is envisaged under the EA 2003 that the wire business, both at the transmission and distribution level, should be segregated and regulated, whereas the supply business could be de-regulated, once effective competition is introduced. Eventually, in order to have full scale retail competition, the Wires Business will have to be separated from the Supply Business, and the operation of the Wire Business de-linked from the operation of the Supply Business. Once this is done, one can have multiple supply licensees, who can procure the required quantum of power and supply to consumers using the common wire network. Such kind of competition will enable the tariffs to go down, as well as enable further improvement in the quality of service and supply, since the supply licensees will have to create differentiation and brand identity by ensuring quality supply.

Apportioning of wires and supply cost

In addition to the expense heads to be excluded while determining the wires cost, the portion of the O&M expenses related to the supply business needs to be excluded. On the other hand, the majority of the capital expenditure related expenses, viz., depreciation, interest and Return on Equity, would have to be included under the Wires Business, rather than the Supply Business, since the wires network is required for the purpose of wheeling electricity from the point of injection to the point of drawal. The Supply Business would require only a small component of the capital expenditure towards billing and collection activity. The following matrix is presently used by distribution licensees in Maharashtra for apportioning the ARR of the distribution licensee between the Wires Business and Retail Supply Business:

Table 11: Allocation of Revenue Requirement between Wires and Supply Business

Particulars	RInfra-D (FY 2009-10)		TPC-D (FY 2009-10)		MSEDCL (FY 2008-09)	
	Wires Business (%)	Supply Business (%)	Wires Business (%)	Supply Business (%)	Wires Business (%)	Supply Business (%)
Power Purchase Expenses	0%	100%	0%	100%	0%	100%
Standby Charges	0%	100%	0%	100%		
Employee Expenses	65%	35%	75%	25%	60%	40%
Administration & General Expenses	63%	37%	33%	67%	50%	50%
Repair & Maintenance Expenses	94%	6%	100%	0%	87%	13%
Depreciation, including advance against depreciation	78%	22%	91%	9%	87%	13%
Interest on Long-term Loan Capital	87%	13%	90%	10%	87%	13%
Interest on Working Capital and on consumer security deposits	7%	93%	0%	100%	9%	91%
Bad Debts Written off	0%	100%	0%	100%	9%	91%
Other Expenses	0%	0%	0%	0%	0%	100%
Income Tax	0%	100%	95%	5%	87%	13%
Transmission Charges intra-State	0%	100%	0%	100%	0%	100%
Contribution to contingency reserves	85%	15%	100%	0%	92%	8%
Return on Equity Capital	88%	12%	97%	3%	80%	20%
Less: Non Tariff Income	0%	100%	88%	12%	0%	100%
Aggregate Revenue Requirement from Retail Tariff	**13%**	**87%**	**6%**	**94%**	**13%**	**87%**

As is clear from above matrix, there is no uniformity of approach in allocation of expenses between the Wires and Retail Supply Business, amongst various distribution licensees and allocation is mainly done based on certain assumptions. To bring uniformity and clarity on this issue, it is proposed that voltage level wise separate accounting of network related costs and supply related costs needs to done for appropriate determination of wheeling charges. This is also as per the requirement of the MERC Tariff Regulations, as reproduced above.

Recovery of the Wires Cost

The method of recovery of the wires cost from the consumers is another area, which needs to be suitably addressed in the new MYT Regulations. The following two mechanisms can be used for recovery of wheeling charges:

- On energy wheeled basis - in terms of Rs/kWh
- On contracted capacity basis - in terms of Rs/kW/month

In this context, the Tariff Policy notified by the Government of India stipulates as follows:

> *"8.5.4 …The fixed costs related to network assets would be recovered through wheeling charges.*
> *8.5.5 Wheeling charges should be determined on the basis of same principles as laid down for intra-state transmission charges and in addition would include average loss compensation of the relevant voltage level."*

Regulation 66 of the MERC Tariff Regulations stipulates

> *"66.1 The Commission shall specify the wheeling charges of the Distribution Licensee in its Order passed under sub-section (3) of Section 64 of the Act:*
>
> *Provided that the charges payable by a Distribution System User under this Part G may comprise any combination of fixed charges and variable charges, as may be specified by the Commission in such Order."*

Consumption at a particular voltage level utilises the network at that voltage as well as at all higher voltages. Therefore, the cost of wheeling electricity at HT voltages should be borne by HT consumers as well as LT consumers, whereas the cost of LT voltage should be borne by the LT consumers alone. The Licensees have to furnish the voltage-wise asset details, and the voltage-wise wheeling costs are further allocated to HT and LT categories based on their Contract Demand. For consumer categories where the contract demand data is not available, especially domestic and commercial consumers, an appropriate load factor can be assumed, to derive the effective Contract Demand.

Based on the data submitted by distribution licensees along with the APR Petition for FY 2008-09 (for RInfra-D and TPC-D) and APR Petition for FY 2007-08 (for MSEDCL), the wheeling charges in terms of Rs/kW/month are summarised below:

	RInfra-D		TPC-D		MSEDCL		
Voltage	**Wheeling Charge (Rs/kW/month)**	**Wheeling Loss (%)**	**Wheeling Charge (Rs/kW/month)**	**Wheeling Loss (%)**	**Voltage**	**Wheeling Charge (Rs/kW/month)**	**Wheeling Loss (%)**
HT level	108	1.50%	78	0.66%	33 kV	20	6%
LT level	121	9.00%	160	0.66%	22 kV	110	9%
					LT level	191	14%

The objective of the EA 2003 in providing open access to consumers was to ensure that competitive forces are able to work, to achieve the overall objective of reduction in tariffs and improvement in quality of supply and customer service. In this context, there is a need to simplify the levy of wheeling charges and wheeling losses, to facilitate supply of electricity by parallel distribution licensee to consumers. In order to operationalise the system and to enable the consumers and distribution licensees to understand the implications correctly, these Wheeling Charges need to be expressed in terms of Rs/kWh, since, the metering and billing is done on the basis of energy consumed in kWh, and this will facilitate practical implementation of the system.

Hence, the Commission in its Clarificatory Order dated July 22, 2009, in Case No. 121 and Case No. 113 of 2008 for RInfra-D and TPC-D, respectively, has clarified that wheeling charges applicable in Rs/kWh terms would be as under:

Table 12: Wheeling Charge and Losses applicable for TPC-D and RInfra-D

	HT		LT	
Particulars	**TPC-D**	**RInfra-D**	**TPC-D**	**RInfra-D**
Wheeling Charge (Rs/kWh)	0.18	0.46	0.37	0.88
Wheeling losses (%)	0.66%	1.50%	0.66%	9%

Introduction of Competition in Distribution Business

The Electricity Act 2003 provides an enabling framework to create a competitive and efficient electricity market, as highlighted below:

a) Section 7 provides for establishment, operation and maintenance of a generating company without obtaining a licence subject to complying with Technical Standards.

b) Section 9 provides for Open Access to captive generators subject to availability of network.

c) Section 12 recognises transmission, distribution and trading of electricity as distinct licenced activities.

d) Sixth Proviso to Section 14 provides for issue of parallel distribution licences to two or more persons through their own distribution network within the same area.

e) Ninth Proviso to Section 14 stipulates that a distribution licensee shall not require a licence to undertake trading in electricity.

f) Section 39 (2) (d) in respect of STU and Section 40 (c) in respect of transmission licensee, specifies that non- discriminatory open access has to be provided to their respective transmission system for use by any licensee or generating company and to any consumer as and when open access is provided by the State Commission.

g) Section 42 (2) mandates the State Commission to introduce Open Access in such phases and subject to such conditions and other operational constraints as may be specified within one year of the appointed date.

h) Section 42 (3) allows any person to obtain supply from a generating company or any licensee other than the distribution licensee of his area subject to payment of surcharge, wheeling charge and additional surcharge.

i) Section 49 provides for open access consumers to enter into agreement with any person for supply or purchase of electricity on such terms & conditions (including tariff) as may be agreed upon by them.

j) Section 60 provides the appropriate Commission to issue such directions to a licensee or generating company if they enter into any agreement or abuse their dominant position or enter into a combination, which is likely to cause an adverse effect on competition in electricity industry.

k) Proviso to Section 62 (1) provides that the appropriate Commission may fix a maximum ceiling of tariff for retail sale of electricity in case where there is more than one distribution licensee in the same area of supply.

l) Section 63 stipulates that the appropriate Commission shall adopt the tariff if such tariff is determined through bidding.

m) Section 65 provides for payment of advance subsidy by the State Government to compensate the person affected by grant of such subsidy.

n) Section 66 mandates the appropriate Commission to endeavour to promote development of a market (including trading) in power.

The National Electricity Policy (NEP) has stressed the need to introduce competition in the power sector. Relevant extracts of the NEP on introduction of competition are as under:

"5.4.5 The Electricity Act 2003 enables competing generating companies and trading licensees, besides the area distribution licensees, to sell electricity to consumers when open access access is introduced by the State Electricity Regulatory Commissions. As required by the Act, the SERCs shall notify regulations by June 2005 that would enable open access to distribution network in terms of sub-section 2 of section 42 which stipulates that open access would be allowed, not later than five years from 27th January 2004 to consumers who require a supply of electricity where the maximum power to be made available at any time exceeds one megawatt. Section 49 of the Act provides that such consumers who have been allowed open access under section 42 may enter into agreement with any person for supply of electricity on such terms and conditions, including tariff, as may be agreed upon by them. While making regulations for open access in distribution, the SERCs will also determine wheeling charges and cross subsidy surcharge as required under section 42 of the Act."

"5.4.7 One of the key provisions of the Act on competition in distribution is the concept of multiple licensees in the same area of supply through their own independent distribution system. State Governments have full flexibility in carving out distribution zones while restructuring the Government Utilities. ***For grant of second and subsequent licence within the area of an incumbent distribution licensee, a revenue district, municipal***

council for a smaller urban area or a municipal corporation for a larger urban area as defined in the Article 243(Q) of the Constitution of India (74th Amendment) may be considered as the minimum area. *The Government of India would notify within three months, the requirement for compliance by applicant for second and subsequent licence for distribution as envisaged in section 14 of the Act.* ***With a view to provide benefit of competition to all sections of the consumers, the second and subsequent licence for distribution in the same area shall have obligation to supply to all consumers in accordance with provisions of section 14 of the Electricity Act 2003****. The SERCs are required to regulate the tariff including connection charges to be recovered by a distribution licensee under the provisions of the Act. This will ensure that second distribution licensee does not resort to cherry picking by demanding unreasonable connection charges from consumers"(****emphasis added****)*

*" **5.7 Competition aimed at consumer benefit:***

5.7.1 *To promote market development, apart of the new generating capacities, say 15% may be sold outside long-term PPAs. As the power markets develop, it would be feasible to finance projects with competitive generation costs outside the long-term power purchase agreement framework. In the coming years, a significant portion of the installed capacity of new generation stations could participate in competitive power markets. This will increase the depth of the power market and provide alternatives for both generators and licensees/consumers and in long run would lead to reduction in tariff.*

For achieving this, the policy underscores the following:-

a) *It is the function of the Central Electricity Regulatory Commission to issue licence for inter state trading, which would include authorisation of trading throughout the country.*

b) *The ABT introduced by CERC at the regional level has had a positive impact. It has also enabled a credible settlement mechanism for intra-day power transfers from licences with surpluses to licences experiencing deficits. SERCs are advised to introduce the ABT regime at the state level within one year.*

c) *Captive generating plants should be permitted to sell electricity to licensees and consumers when they are allowed open access by SERCs under section 42 of the act.*

d) *Development of power market would need to be undertaken by Appropriate Commission in consultation with all concerned.*

e) *The Central Commission and the State Commissions are empowered to make regulations under section 178 and section 181 of the Act respectively. These regulations will ensure implementation of various provisions of the Act regarding encouragement to competition and also consumer protection. The Regulatory Commissions are advised to notify various regulations expeditiously.*

f) *Enabling regulations for inter and intra state trading and also regulations on power exchange shall be notified by the appropriate Commission within six months."*

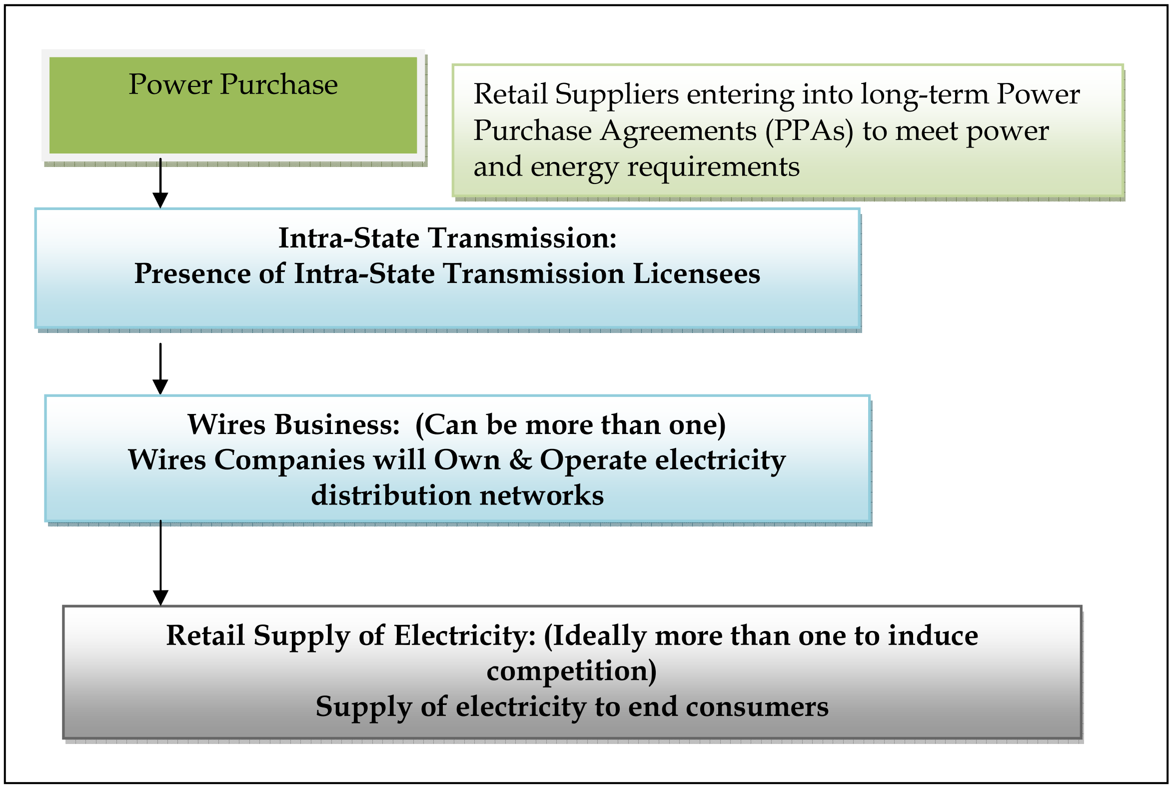
In India, the parallel distribution companies with common carrier/independent distribution network as envisaged in the EA 2003 are yet to come up in spite of the enabling legal framework provided in the EA 2003. The consumers continue to buy power from monopoly distribution licensees without any choice of supplier.

As mentioned earlier, in Mumbai, with the notification of the MERC (Specific Conditions of Distribution Licence for The Tata Power Company Limited) Regulations, 2008 on August 20, 2008, TPC has a distribution licence which spans the distribution licence areas of both, RInfra-D as well as BEST. Thus, in both these licence area, there are two suppliers of electricity. However, competition in the retail supply of electricity without insisting on creation of a parallel distribution network will go a long way in introduction of competition in retail supply of power.

The international experience in introducing competition in retail supply shows that instead of parallel networks, multiple suppliers are allowed to supply through a common network, as it is not economically viable to duplicate the existing distribution network due to the sunk-cost associated with it and the scale of economies derived from network operation. In this context it becomes imperative to separate the supply from wire business to make retail supply competitive.

The multi supplier model is shown in the block diagram below:

Figure 1: Multi-Supplier Model



With a view to introduce competition, it is proposed that in the long-term, the Wires Business (covering the distribution network) should be separated from Retail Supply Business. The retail supply licensees should be able to supply power to any consumer (irrespective of the load and supply voltage) through the existing distribution lines/network subject to payment of wheeling charges to the owner of the wire network. Requirement of meeting Universal Service Obligation (USO) would form an essential part of retail supply licence conditions, to prevent cherry picking of consumers. It is proposed that

1. Wires Business
    a. Will own and maintain the distribution network.
    b. Would be responsible for up-gradation to network to meet the standards of performance.

c. The Power Purchase Agreements would have to be transferred to the Retail Supply Business.

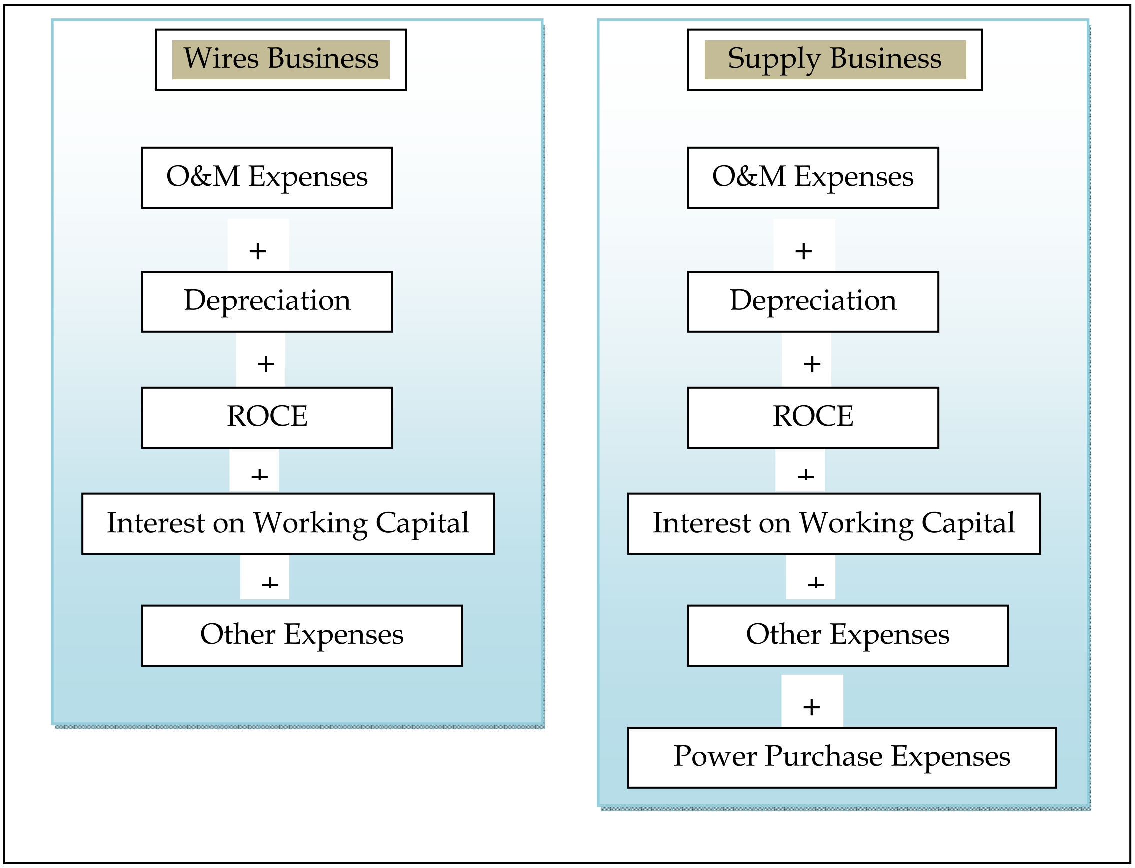
2. Retail Supply Business

   a. Would be responsible for retail supply of electricity.

   b. Their duties would include all the activities related to consumer interface which would include billing, collection and other value added services, viz., reactive power compensation, etc.

However, this is a long-term solution, since the distribution licences issued to the distribution licensees would have to be amended accordingly, and the necessary regulatory framework to ensure that the wires network is available seamlessly to the retail suppliers, irrespective of ownership of the network, and which addresses the related issues of metering, consumer complaint handling, balancing related issues, etc., would have to be put in place by the Commission.

In the interim, the Revenue Requirement and tariff of the Wires and Retail Supply Business would have to be determined separately. The representative components of revenue requirement of Wires and Retail Supply business are shown in the Block Diagram below:



6.2 *Distribution Loss vs. AT&C loss*

Technical Losses: Every element in a power system (a line or a transformer, etc.) offers resistance to power flow and thus consumes some energy while performing the duty expected of it. The cumulative energy consumed by all these elements is classified as **"Technical Loss".**

Commercial Loss: Losses that occur on account of non-performing and under performing meters, wrong application of multiplying factors, defects in CT and PT circuitry, meters not read, pilferage by manipulating or by-passing of meters, theft by direct tapping, etc., correspond to energy consumed but not metered or billed and are hence, categorised as "**commercial losses**".

The combination of “Technical” and “Commercial” losses in the electricity distribution business is termed as **Distribution loss.** It is unfortunate that in addition to the above, there is also a loss in revenue collected due to non-realisation of billed amount. The aggregate of Distribution loss and revenue loss due to non-realisation (collection inefficiency) is termed as **“AT&C loss”** (Aggregate Technical and Commercial loss). Therefore, AT&C loss of the distribution licensee is the combination of technical losses, commercial losses and collection inefficiency.

Since the beginning of the reform process, distribution loss reduction has been one of the primary benchmarks for measuring the performance of a distribution Utility. The SERCs have either adopted distribution losses reduction or AT&C loss reduction approach as a performance benchmark. The Commission, in the existing MERC Tariff Regulations as well as in Tariff Orders has adopted the distribution loss reduction approach for measuring the performance of distribution licensees. At this point, it would be appropriate to analyse the merits and demerits of each approach.

Distribution loss reduction is a widely used approach at the national and international level to measure the performance of the distribution licensee. Distribution loss is simple to compute as it takes into account the energy input and energy billed to the consumers, thereby taking into consideration the technical losses and unaccounted energy due to theft and misuse. However, in many cases, the actual distribution losses are estimated to be higher than the reported losses, on account of the assessment of un-metered agricultural consumption. Thus, distribution loss method has certain limitations, particularly in case of significant un-metered consumption.

On the other hand, AT&C loss method covers the whole arena of losses of the distribution system and includes technical losses, billing inefficiency, theft, and collection inefficiency. If units sold, units billed and units collected can be computed accurately, then AT&C loss method would be the best indicator of measuring the efficiency of the distribution licensee. However, computation of AT&C losses leads to creation of complexities as it combines technical and commercial parameters, i.e., energy input in units and amount collected in Rupees. Some other issues in AT&C loss computation are as follows:

- Units realised have to be derived based on units billed and collection efficiency

- Units billed may not be measured accurately due to un-metered consumption, thus having the same deficiency as distribution loss method
- Revenue collected may include the past arrears
- Amount collected against other charges may not be separately accounted for
- If AT&C loss computation is attempted on cash basis alone (Total amount collected/total amount spent), it can lead to distorted results.

Considering the high commercial losses in the Indian power system, the Tariff Policy framed under Section 3 of Electricity Act 2003 has favoured the adoption of the AT&C loss method, as reproduced below:

> *"5(a) The State Commission may consider 'distribution margin' as basis for allowing returns in distribution business at an appropriate time. The Forum of Regulators should evolve a comprehensive approach on "distribution margin" within one year.* ***The considerations while preparing such an approach would, inter-alia, include issues such as reduction in Aggregate Technical and Commercial losses****, improving the standards of performance and reduction in cost of supply."* ***(Emphasis added)***

However, till date, only the Delhi Electricity Regulatory Commission has adopted the AT&C loss approach for approving the ARR and tariff of distribution licensees. The Orissa Electricity Regulatory Commission has recognised AT&C Loss as a performance parameter for measuring, monitoring and controlling the efficiency of the operation of the distribution licensees, however, for approving the ARR and tariff, OERC has considered distribution loss targets and not the AT&C loss targets.

The Commission has specified the Distribution Loss reduction trajectory while determining the ARR of the distribution licensees.

In this context, the FOR report on MYT framework and distribution margin recommends as under:

> *"2.4.13 After discussing the merits and demerits of measuring losses in terms of AT&C loss or Transmission and Distribution (T&D) loss,* ***it was agreed that it is only the distribution loss which could be measured, and transmission losses should be***

__dealt with separately__. For purposeful measurement of distribution loss, Automated Meter Reading (AMR) based feeder metering and transformer metering is essential…."

The question to be asked here is whether the distribution licensees' collection inefficiency should also be passed on to the consumers. It appears illogical that the other consumers should pay for the licensees' inability to collect the billed amounts from the consumers to whom it has sent the bills. Further, the inclusion of collection inefficiency by determining the tariffs on the basis of AT&C loss will result in further increase in the consumers' tariff. Considering this aspect and in view of issues discussed above, **it is proposed to continue with Distribution Loss approach for approving the ARR and Tariff of Distribution Licensees in the State**.

6.3 Methodology for Benchmarking

Benchmarking is a tool, which a Regulator may use to develop the competitive market. The Regulator, while setting the benchmark, will have to consider the need to incentivise the efficient player/s in the industry and also a need to reset the benchmarks considering the market trends. By doing this, an efficient company may earn more returns by undertaking its operations in a cost effective/efficient manner while an inefficient company will always be a loser, due to its inefficient operations. Type of distribution networks, viz., underground/overhead, HT-LT ratio, etc., would also need to be given due consideration while arriving at a benchmark. However, some deviation in performance from other better performing Utilities can be accommodated, but it may not be acceptable to pass on inefficiencies of distribution licensees on to the consumers. Moreover, under Performance Based Regulation, Utilities are regulated on a normative basis.

For benchmarking for distribution licensees in Maharashtra, a comparison with distribution licensees having similar profile of consumer mix, distribution network, viz., Underground Vs Overhead lines, HT-LT ratio, type of licence area (city, State, etc.) needs to be undertaken, else, it may lead to distorted results. ABPS Infra is of the opinion that benchmarking should be done based on:

a) **Past performance** of Utilities.

b) **Intra-State comparison:** Comparison of performance of distribution licensees in Maharashtra with each other.

c) **Inter-State comparison**: Comparison of performance of distribution licensees in Maharashtra with performance of distribution licensees in other States, with similar profile of consumer mix, distribution network, viz., Underground Vs Overhead lines, HT-LT ratio, type of licence area (city, State, etc.).

The list of distribution licensees considered for benchmarking are shown in the Table below:

Table 13: Profile of Distribution Licensees

Sl.	Distribution Licensees	Abbreviation	Type of License Area	Profile
A	**Andhra Pradesh**			
1	Andhra Pradesh Central Power Distribution Company Ltd	APCPDCL	State	Heterogeneous (City and Rural Mixed)
2	Andhra Pradesh Eastern Power Distribution Company Ltd	APEPDCL	State	Heterogeneous (City and Rural Mixed)
3	Andhra Pradesh Northern Power Distribution Company Ltd	APNPDCL	State	Heterogeneous (City and Rural Mixed)
4	Andhra Pradesh Southern Power Distribution Company Ltd	APSPDCL	State	Heterogeneous (City and Rural Mixed)
B	**Karnataka**			
1	Chamundeshwari Electricity Supply Company Ltd	CESC-K	State	Heterogeneous (City and Rural Mixed)
2	Gulbarga Electricity Supply Company Ltd	GESCOM	State	Heterogeneous (City and Rural Mixed)
3	Hubli Electricity Supply Company Ltd	HESCOM	State	Heterogeneous (City and Rural Mixed)
4	Mangalore Electricity Supply Company Ltd	MESCOM	State	Heterogeneous (City and Rural Mixed)
5	Bangalore Electricity Supply Company Ltd	BESCOM	State	Heterogeneous (City and Rural Mixed)
C	**Delhi**			
1	BSES Yamuna Power Ltd	BYPL	City	Urban
2	BSES Rajdhani Power Ltd	BRPL	City	Urban
3	North Delhi Power Ltd	NDPL	City	Urban

Sl.	Distribution Licensees	Abbreviation	Type of License Area	Profile
D	**Gujarat**			
1	Paschim Gujarat Vij Co.Ltd.	PGVCL	State	Heterogeneous (City and Rural Mixed)
2	Dakshin Gujarat Vij Co.Ltd.	DGVCL	State	Heterogeneous (City and Rural Mixed)
3	Uttar Gujarat Vij Co.Ltd.	UGVCL	State	Heterogeneous (City and Rural Mixed)
4	Madhya Gujarat Vij Co Ltd.	MGVCL	State	Heterogeneous (City and Rural Mixed)
5	Torrent Power Ltd.-Ahmedabad and Gandhi Nagar	TPL- Ahmd	City	Urban
6	Torrent Power Ltd.- Surat	TPL-Surat	City	Urban
E	**Rajasthan**			
1	Jaipur Vidyut Vitran Nigam Ltd	Jaipur Discom	State	Heterogeneous (City and Rural Mixed)
2	Ajmer Vidyut Vitran Nigam Ltd	Ajmer Discom	State	Heterogeneous (City and Rural Mixed)
3	Jodhpur Vidyut Vitran Nigam Ltd	Jodhpur Discom	State	Heterogeneous (City and Rural Mixed)
F	**Calcutta Electricity Supply Company ltd**	CESC	City	Urban
G	**Maharashtra**			
1	Maharashtra State Electricity Distribution Company Ltd	MSEDCL	State	Heterogeneous (City and Rural Mixed)
2	Reliance Infrastructure Ltd-Distribution	RInfra-D	City	Urban
3	The Tata Power Company Ltd-Distribution	TPC-D	City	Urban
4	Brihanmumbai Electricity Supply & Transport undertaking	BEST	City	Urban

ABPS Infra has undertaken inter-State comparison based on type of licence area, as discussed below:

a) RInfra-D, TPC-D and BEST have been benchmarked with their own past performances and also with **city based licensees** (Urban profile) like BRPL, BYPL, NDPL, etc.

b) MSEDCL has been benchmarked with its own past performances and also with **State based Licensees having heterogeneous profile**.

ABPS Infra has proposed different benchmarks for different distribution licensees considering the peculiar problems in specific cases. Hence, f**or Distribution business, ABPS Infra has proposed benchmarking of distribution licensees based on their past performance and comparison of various parameters with selected distribution licensees across India having similar profile.**

6.4 Distribution Loss Reduction Trajectory

In the multi-year tariff regime, the Commission is required to set year-wise benchmarks for distribution loss reduction, which may be in terms of percentage reduction with respect to opening loss level or by stipulating absolute numbers. The issues, which need to be addressed for the next Control Period, are the criteria for determining the base level losses and loss reduction trajectory.

The Commission, under its MERC Tariff Regulations and the Retail Supply Tariff Orders, has specified that the distribution licensee, while making the Petition for Aggregate Revenue Requirement/Multi-Year Tariff and tariff determination shall furnish information about total and voltage-wise distribution losses, as well as break-up between technical and commercial losses, and also propose a loss reduction trajectory. However, while BEST and RInfra-D have furnished their estimates of break-up between technical and commercial losses, none of the distribution licensees have submitted details of voltage-level losses.

MSEDCL is the only distribution licensee, which is having an un-metered consumption for agriculture flat-rate consumers. However, even for the metered agricultural category, it has been found that only around 65% to 70% of the meters are giving normal readings, while the rest are either defective or non-functional for some reason. Hence, actual distribution losses for lower voltages can only be ascertained after completion of metering and energy audit work up to distribution transformer level.

The issue here is whether the actual distribution losses or the targets specified by the Commission should be considered as the base level of distribution losses for stipulating the loss reduction trajectory for the next Control Period. In this context, the Tariff Policy notified by the Government of India in January 2006 stipulates,

> *"5(h) 2) In cases where operations have been much below the norms for many previous years the initial starting point in determining the revenue requirement and the improvement trajectories should be recognized at "relaxed" levels and not the "desired" levels. Suitable benchmarking studies may be conducted to establish the "desired" performance standards. Separate studies may be required for each utility to assess the capital expenditure necessary to meet the minimum service standards."*

In this context, the FOR report on MYT framework and distribution margin recommends as under:

> *"6.1.10* ***Only the distribution loss should be measured****, essentially by AMR- based feeder metering and DT metering. Transmission losses should be dealt with separately.*
>
> *6.1.11 Data on distribution loss levels should be verified through a third party as envisaged in the Tariff Policy. The services of accredited energy auditors and academic institutions such as IITs and other engineering colleges could be utilised for this.*
>
> *6.1.12 The loss levels may be considered at actual level at the start of the first control period and an achievable trajectory may be given under the MYT framework.* ***However, the loss level at the start of the subsequent control periods may be fixed keeping in view the targets set in the previous control period, actual performance and efforts at achievement. The norms should be revised after every MYT period with prospective effect****.*
>
> *6.1.13 If the distribution licensee does not reduce the losses in accordance with the specified trajectory, despite undertaking capital expenditure towards reducing the losses, this would amount to violation of the direction and in such cases action under section 142 may be considered by the SERC.*
>
> *6.1.14 To accelerate loss reduction, an incentive and dis-incentive mechanism for field staff of the utility at the circle and sub-division level should also be put in place."* ***(emphasis added)***

Hence, for the second Control Period, it is proposed that the normative distribution losses, as approved by the Commission for the first Control Period shall be considered for setting opening loss levels and loss reduction trajectory, after giving due consideration to the actual distribution loss levels achieved by the distribution licensees, and efforts taken to reduce the distribution losses.

The Commission, in its MYT Orders, has specified the percentage reduction trajectory for the Control Period for all the distribution licensees. It is proposed that the same practice will continue, and the **percentage loss reduction targets for each year of the Control Period would be specified, along with the absolute loss levels for ease of reference.**

Distribution Loss reduction is a primary benchmark for determining the performance of any distribution licensee over a period of time. The distribution licensees in the State have been given loss reduction targets by the Commission in their respective Multi-Year Tariff (MYT) Orders, except for MPECS, which has not filed a MYT Petition for various reasons. The Commission has stipulated the following loss reduction targets for the DISCOMs:

Table 14: Approved Distribution losses for Distribution licensees

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
MSEDCL	30.20%	26.20%	22.20%	18.20%
RInfra-D	10.77%	11.00%	10.75%	10.50%
TPC-D*	2.93%	2.21%	2.93%	0.66%
BEST	11.90%	11.00%	10.50%	10.00%

Note: * - for TPC-D, the loss reduction trajectory was based on estimates, due to the absence of metering data for energy injected at T <> D interface. The loss level approved for FY 2009-10 is based on metered data.

Distribution loss trajectory for City based distribution licensees

The distribution losses for various city based distribution licensees are tabulated below:

Table 15: Distribution loss comparison for City based distribution licensees

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
CESC		15.36%	15.11%	14.90%
BYPL	39.03%	33.42%	29.99%	25.89%
BRPL	35.63%	30.89%	22.88%	19.83%

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
NDPL	27.30%	20.72%	19.75%	18.27%
RInfra-D	10.77%	11.00%	10.75%	10.50%
TPC-D	2.93%	2.21%	2.93%	0.66%
BEST	11.90%	11.00%	10.50%	10.00%
TPL- Ahmd		10.48%	10.43%	10.25%
TPL- Surat		6.01%	6.00%	6.00%

From the above table, it is observed that distribution licensees of Mumbai, viz., RInfra-D, TPC-D and BEST, are performing reasonably well in terms of distribution losses. Hence, it is proposed to determine the trajectory for the distribution licensees in Mumbai area based on their own past performance. Hence, following loss reduction trajectory is proposed to be adopted:

1. RInfra-D: A loss reduction trajectory of 0.25% per year for each year of the second Control Period is proposed, in view of the prevailing low loss levels.
2. TPC-D: It is proposed to specify the loss reduction trajectory for each year of the second Control Period, based on the estimate of additional consumers added to TPC-D's consumer base, HT-LT ratio, etc..
3. BEST: A loss reduction trajectory of 0.25% per year for each year of the second Control Period is proposed, in view of the prevailing low loss levels.

Distribution loss trajectory for State-based distribution licensees

Distribution losses for various State based distribution licensees are tabulated below:

Table 16: Distribution loss comparison for State based distribution licensees

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
Andhra Pradesh				
APCPDCL	20.76%	19.15%	17.87%	13.04%
APEPDCL	17.55%	16.37%	15.27%	11.12%
APNPDCL	21.07%	19.05%	17.97%	14.71%
APSPDCL	19.74%	18.43%	17.17%	12.50%
Karnataka				
CESC-K	22.00%	22.00%	21.00%	19.50%
GESCOM	27.05%	31.00%	30.50%	29.10%

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
HESCOM	25.00%	25.30%	24.30%	22.80%
MESCOM	15.00%	14.90%	14.80%	14.50%
BESCOM	20.50%	21.35%	20.40%	18.90%
Gujarat				
PGVCL	34.22%	32.00%	30.00%	28.00%
DGVCL	16.59%	15.59%	14.45%	13.45%
UGVCL	19.45%	16.95%	16.00%	15.00%
MGVCL	18.24%	16.74%	15.00%	14.00%
Rajasthan				
Jaipur Discom	29.51%	26.56%	23.90%	
Ajmer Discom	34.08%	30.67%	27.60%	
Jodhpur Discom	31.29%	28.16%	25.35%	
MSEDCL	30.20%	26.20%	22.20%	18.20%

The loss reduction trajectory for MSEDCL as approved by the Commission was 4% per year for each year of the first Control Period.

It is important to look at the various directives issued by the Commission to erstwhile MSEB/MSEDCL to complete 100% metering, with a view to compute distribution losses accurately, as compiled below:

A. In its first Tariff Order for FY 2000-01, the Commission directed MSEB to complete the meterisation of all consumers by March 31, 2003, as reproduced below:

> *"While preparing the MMP, the MSEB is directed to follow the below mentioned principles:*
>
> *1. All consumers will be provided with meters by 31 March, 2003.*
>
> *2. Regional balance as regards the population of meters should be maintained.*
>
> *3. All urban consumers should be metered on priority.*
>
> *4. All HT industrial consumers should be metered before 30 September 2000.*
>
> *5. All other HT consumers excluding Railways should be provided with TOD meters before 31 December 2000.*
>
> *6. High consumption/ connected load consumers should be metered on preference."*

B. In its Tariff Order for FY 2001-02 dated January 10, 2002, the Commission directed MSEB to achieve the metering targets as per schedule.

C. In its Tariff Order for FY 2003-04 dated December 1, 2003, the Commission reiterated its earlier directive to the MSEB to achieve 100% metering for LT agriculture consumers at the earliest, assigning priority to the appropriate DTC metering and ensuring close monitoring to arrive at statistically significant output for assessed agricultural consumption, and operating hours.

D. In its Tariff Order for FY 2006-07 dated October 20, 2006, the Commission directed MSEDCL to comply with the statutory provisions as well as the Tariff Policy in respect of individual consumer metering.

E. In its MYT Tariff Order for FY 2007-08 to FY 2009-10 dated May 18, 2007, the Commission directed MSEDCL to ensure 100% metering at all levels, starting from feeder level to DTC level, to consumer level as stipulated in the EA 2003. MSEDCL was also directed to ensure that the necessary DTC metering and feeder metering arrangements are completed as scheduled, and the feeder-wise energy related information with consumer database is compiled and submitted to the Commission by end-October 2007.

F. In its APR Order for FY 2007-08 dated June 20, 2008 directed MSEDCL to strive to ensure 100% metering of all consumption, including agricultural consumption, if not at the individual level, then at least at the feeder level and DTC level.

Hence, MERC has been repeatedly directing MSEDCL to accomplish 100% metering, but MSEDCL is still very distant from achieving it.

The Appellate Tribunal for Electricity (ATE), in a recent Judgment dated July 21, 2009 in Appeal No. 108 of 2007, has observed as under:

".... However, the level of cross subsidization would be known only when the distribution losses of MSEDCL are correctly determined. Till such time, achievement of one of the key objectives of the Act of 2003 of having transparent policies regarding subsidies would not be achieved. Though, we recognize that the process requires some time to achieve the level of 100% meterisation. ***However, we need to be alive to the other important objective of the Act i.e. protection of consumers' interest****. Non-implementation of meterisation programme in a time-bound manner means that the achievement of these objectives would remain a distant dream and would test the efficacy of the regulatory system. At the end of the day, if the consumer remains unsatisfied, there is a need for introspection as to why the consumer is not satisfied? The Apex Court has many a times in the past observed that justice should not only be done but should also be seen to have been done. May be, there is a need for the State Commission to analyze that despite the State Commission regulating so closely the progress of meterisation, why the consumers are feeling that MSEDCL has been allowed more time than required?* ***Hence we deem it fit to advise the State Commission to sharpen its focus for accelerated meterisation of consumers and reduction of Distribution losses in a time bound manner, with renewed drive and vigor with an in-built system of strong incentive to the licensee, MSEDCL."***

Hence, it is important to emphasise that MSEDCL should achieve Feeder level and DTC level metering, as well as individual metering, to present the distribution losses in a more accurate manner.

The distribution loss level of MSEDCL is targeted at 18.2% for FY 2009-10. In accordance with the FOR recommendations in this regard, the opening loss level for the second Control Period is proposed to be considered as 18.2%. Given the heterogeneous nature of MSEDCL's distribution licence area, and considering the mix of rural and urban consumption, and vast area to be covered, a loss reduction trajectory of 1% per year for each year of the second Control Period is proposed, such that the distribution loss level in the last year of the second Control Period will be 13.2%.

6.5 Operation & Maintenance Expenses

The O&M expenses comprise Employee Expenses, R&M Expenses and A&G expenses, and constitute a significant part of the Aggregate Revenue Requirement of the distribution licensee.

In this context, the FOR Report on MYT framework and distribution margin has recommended as under:

> *"2.5.14 O&M expenditure should be allowed on a normative basis by prescribing this in the regulations."*

In its existing MERC Tariff Regulations, the Commission has approved O&M expenses for distribution licensees based on the past performance, with certain escalation factor, based on Consumer Price Index/Wholesale Price Index. However, it is more appropriate to allow the O&M expenses on a normative basis, rather than regulating the same on the basis of actual expenses, with the need to true up the same, etc.

Approaches for determining the normative O&M expenses

The following three options can be adopted for determining the normative O&M expenses, viz.,

Option 1: Size of Distribution System or GFA method
Option 2: Number of consumers served
Option 3: Mixed Approach for each component

Option 1: Size of Distribution System or GFA method

The size of distribution system is one of the drivers of O&M expenses, since the size of the system would determine the amount of service and maintenance required. The size of asset has direct linkage with the R&M expenses required for maintaining the system and number of employees required for managing the distribution system. The following formula can be used for determining the O&M expenses:

O&M expense = k * Gross fixed asset, where k is a constant or may be expressed in terms of percentage (%) and which governs the relationship between GFA and O&M expenses.
k can be determined on the basis of past years' data.

Option 2: Number of consumer served

O&M expenses have direct correlation with the number of consumers served and therefore, the norms for O&M expenses can be determined on the basis of number of consumers served in a particular year, using the following formula:

O&M expense = k * Number of consumers, where k is a constant governing the relationship between number of consumers served and O&M expenses

k can be determined on the basis of past years' data.

Option 3: Separate treatment for each component

Under this approach, employee expenses, A&G expenses, and R&M expenses are treated separately. In this approach, growth drivers for each of the expenses are considered separately, in accordance with the most appropriate driver for movement of each head of O&M expenses.

a. Employee Expense

Employee expenses include salary, wage arrears, and terminal benefits, etc. Employee expense increases every year due to salary increase and promotion of employees. The minimum increase in salary expense would be expected to be such that it offsets the effect of inflation. One such indicator denoting the inflation effect is Consumer Price Index (CPI), reflecting the increase in price of consumer goods.. It is proposed that the Commission may consider the point to point inflation over CPI numbers for Industrial Workers (as per Labour Bureau, Government of India) for a period of 3 years, i.e., previous three years before first year of second Control Period, to smoothen the inflation curve. A relationship can also be derived linking the employee expenses to the number of consumers being served as well as the energy sold in units.

b. A&G Expenses

Administrative & General (A&G) expenses comprise expenses on office administration, rentals, travel, communication, telecommunication and other overheads, etc. Expenditure on these parameters increases every year, and is linked to inflation indices, i.e., CPI and WPI. It is proposed that the Commission may consider the point to point inflation over WPI numbers (as per Office of Economic Advisor of Govt. of India) and CPI numbers for Industrial Workers (as per Labour Bureau, Government of India) for a period of 3 years, i.e., previous three years before first year of second Control Period, to smoothen the inflation curve. It is proposed to consider a weight of 60% to WPI and 40% to CPI, based on the expected relationship with the cost drivers. However, main growth driver for A&G expenses remains the number of consumers served and energy sales in units.

Further, it is proposed that expenses towards contributions/donations incurred by distribution licensees or Utilities would not be considered while determining the A&G expenses, as social initiatives undertaken by Utilities, is primarily driven by social responsibility and an urge to serve the society. Cost associated towards social causes and other corporate responsibility shall be funded by profits of that Utility, and shall not be reimbursed by consumers.

c. Repair & Maintenance (R&M) Expenses

R&M activity in terms of scheduled and break-down maintenance is a part of any running business. Suitable provision for R&M expenses needs to be made for smooth operation of distribution system. R&M expenses increase with the vintage of the equipment. In the initial years of operation, R&M expense is low due to new components, which increases as the assets grow older. The normative R&M expenses can either be linked to the Gross Fixed Assets or linked to weighted average of CPI and WPI.

It is suggested that the R&M expenses are directly correlated to the asset base, and normative R&M expenses may be specified as a percentage of the Gross Fixed Assets. The normative employee expenses may be specified in proportion to the number of units sold or number of consumers, as appropriate. The A&G expenses would tend to move in relation with the number of consumers and geographical spread of the licence area, and may have to be specified in proportion to the number of consumers, as appropriate. The determination of each expense head separately will also facilitate the determination of wheeling charges, since the different expenses have to be apportioned between the Wires Business and Retail Supply business on the basis of different parameters, in the absence of separate accounting of the same at present.

The other option of fixing the normative O&M expenses on a consolidated basis also has certain merits, viz., it imparts flexibility to the licensees to manage their expenditure, since they can decide whether to outsource certain activities (which will increase the A&G expenses) vis-à-vis doing it using own employees (which will increase the employee expenses).

After considering the merits and demerits of the above approaches, it is proposed that for distribution licensees, the employee expenses, A&G expenses and R&M expenses be specified separately, rather than as consolidated O&M expenses. The following approach is proposed for determination of operational norms for each head of O&M expenses:

Employee expenses	:	linked to number of consumers or per unit of sales, based on past five years' trend, and escalated at CPI, if required
A&G expenses	:	linked to number of consumers or per unit of sales, and based on past five years' trend, to be escalated at Ratio of WPI:CPI
R&M expenses	:	Percentage of Opening GFA for the year

6.5.1 Benchmarking O&M expenses for City based Distribution Licensees

The O&M expenses approved for the city based distribution licensees by the Commission in the State of Maharashtra for the period from FY 2006-07 to FY 2009-10 has been analysed below. Sales, number of consumers and GFA approved by the Commission have been used for benchmarking purposes as tabulated below:

Sales **MU**

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
RInfra-D	7,453	7,807	8,230	8,676
TPC-D	2,522	2,506	2,468	2,638
BEST	3,800	4,024	4,103	4,257

Consumers **Number**

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
RInfra-D	2,513,697	2,689,258	2,727,963	2,807,347
TPC-D	23,327	23,630	27,690	33,287
BEST	944,192	944,192	959,984	975,823

GFA **Rs Crore**

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
RInfra-D	1924	2347	2428	2607
TPC-D	359	395	437	483
BEST	1085	1157	1244	1310

Employee Expenses

The employee expenses approved for the three city based distribution licensees by the Commission in the State of Maharashtra for the period from FY 2006-07 to FY 2009-10, and the relationship with the different growth drivers has been analysed below.

Table 17: Net Employee Expenses of City based Distribution Licensees in Maharashtra

Employee Expenses **Rs Crore**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
RInfra-D	225	266	286	307
TPC-D	11	14	18	23
BEST	138	133	143	153

The ratio analysis is given in the Table below:

Table 18: Ratio Analysis for benchmarking Employee Expenses

Employee Expense/unit **Rs/unit**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
RInfra-D	0.30	0.34	0.35	0.35	0.34
TPC-D	0.04	0.05	0.07	0.09	0.07
BEST	0.36	0.33	0.35	0.36	0.35

Employee Cost/consumer **Rs lakh /'000 Consumer**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
RInfra-D	9	10	10	11	10.06
TPC-D	46	58	66	70	60.11
BEST	15	14	15	16	14.84

As seen from the above Tables:

- It will be difficult to benchmark the distribution licensees within Maharashtra based on comparison with each other.
- Intra-State comparison of various parameters, viz., sales and number of consumers for TPC-D would not be appropriate as its consumer mix and quantum of sales is not comparable with other distribution licensees. For TPC-D, it is proposed to do benchmarking with its own past performance. Hence, it is proposed that norm of employee expenses shall be 7 paise per unit of sales.
- For RInfra-D and BEST, inter-State benchmarking with city based distribution licensees could be a better option.

The inter-State ratio analysis of various parameters on which the employee expenses are dependent on, viz., sales, number of consumers, have been summarised below:

Table 19: Inter-State Ratio Analysis for benchmarking Employee Expenses

Employee Expenses/unit Sales **Rs/unit**

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
CESC	0.24	0.28	0.27	0.28	0.27
BYPL	0.46	0.30	0.40	0.33	0.37
BRPL	0.23	0.24	0.26	0.22	0.24
NDPL	0.33	0.28	0.30	0.27	0.30
RInfra-D	0.30	0.34	0.35	0.35	0.34
TPC-D	0.04	0.05	0.07	0.09	0.07
BEST	0.36	0.33	0.35	0.36	0.35
TPL-Ahmd			0.13	0.12	0.13
TPL- Surat		0.19	0.11	0.11	0.11

Employee Expenses/Consumer **Rs Lakh /'000 consumer**

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
CESC	8.62	10.03	10.29	10.81	9.94
BYPL	14.48	11.08	13.43	11.57	12.64
BRPL	11.74	12.99	12.90	10.88	12.12
NDPL	18.21	15.23	15.29	14.02	15.69
RInfra-D	8.94	9.90	10.47	10.92	10.06
TPC-D	46.43	57.77	66.02	70.24	60.11
BEST	14.66	14.11	14.89	15.72	14.84
TPL-Ahmd			4.21	4.34	4.28
TPL- Surat		6.83	5.73	5.84	5.78

As seen from the above Tables, for RInfra-D and BEST, while the employee expenses have been increasing in absolute terms, the average employee expenses have ranged around 34 to 35 paise per unit of sales over the years, and have been around Rs. 10.06 lakh per thousand consumer, which is quite high as compared to CESC and TPL. Hence, the proposed norm for employee expenses for RInfra-D and BEST is 25 paise per unit of sales.

A&G Expenses

The A&G expenses approved by the Commission for the city based distribution licensees in the State of Maharashtra for the period from FY 2006-07 to FY 2009-10 has been analysed below.

Table 20: Net A&G Expenses of City based Distribution Licensees in Maharashtra

A&G Expenses **Rs Crore**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
MSEDCL	148	156	181	
RInfra-D	96	99	105	112
TPC-D	11	12	14	14
BEST	73	68	73	77

The intra-State ratio analysis of various parameters on which the A&G expenses are dependent, viz., sales and number of consumers, have been summarised below.

Table 21: Intra-State Ratio Analysis for benchmarking A&G Expenses

A&G Expense/unit **Rs/unit**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
RInfra-D	0.13	0.13	0.13	0.13	0.13
TPC-D	0.05	0.05	0.06	0.05	0.05
BEST	0.19	0.17	0.18	0.18	0.18

A&G Expense/consumer **Rs lakh /'000 Consumer**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
RInfra-D	3.8	3.7	3.9	4.0	3.84
TPC-D	49.1	52.3	51.9	42.1	48.85
BEST	7.7	7.2	7.6	7.9	7.60

As seen from the above Tables:

- It will be difficult to benchmark the distribution licensees within Maharashtra based on comparison with each other.
- Intra-State comparison of various parameters, viz., sales and number of consumers for TPC-D would not be appropriate as its consumer mix and quantum of sales is not comparable with other distribution licensees. For TPC-D, the better option could be benchmarking with its own performance. Hence, the proposed norm of A&G expenses for TPC-D is 5 paise per unit of sales.

- For RInfra-D and BEST, inter-State benchmarking with other city based distribution licensees could be a better option.

The inter-State ratio analysis of various parameters on which the A&G expenses are dependent on, viz., sales, number of consumers, have been summarised below:

A&G Expenses/unit Sales **Rs/unit**

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
CESC	0.05	0.09	0.08	0.09	0.08
BYPL	0.13	0.11	0.12	0.11	0.12
BRPL	0.11	0.10	0.12	0.12	0.11
NDPL	0.07	0.06	0.06	0.06	0.06
RInfra-D	0.13	0.13	0.13	0.13	0.13
TPC-D	0.05	0.05	0.06	0.05	0.05
BEST	0.19	0.17	0.18	0.18	0.18
TPL- Ahmd			0.06	0.06	0.06
TPL- Surat		0.19	0.08	0.08	0.08

A&G Expenses/Consumer **Rs Lakh /'000 consumer**

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
CESC	1.90	3.14	3.19	3.43	2.92
BYPL	4.14	4.13	3.92	3.82	4.00
BRPL	5.80	5.72	5.92	5.96	5.85
NDPL	3.73	3.35	3.14	3.09	3.33
RInfra-D	3.80	3.69	3.86	3.98	3.84
TPC-D	49.08	52.26	51.90	42.15	48.85
BEST	7.71	7.24	7.55	7.88	7.60
TPL- Ahmd			2.14	2.20	2.17
TPL- Surat		6.68	4.19	4.27	4.23

As seen from the above Tables, for RInfra-D and BEST, while the A&G expenses have been increasing in absolute terms, the average A&G expenses have ranged around 13 to 18 paise per unit of sales, respectively, over the years, and have been around Rs. 4 lakh to Rs 8 lakh per thousand consumer, which is quite high as compared to CESC and TPL. Hence, the proposed norm for A&G expenses for RInfra-D and BEST is 10 paise per unit of sales.

R&M Expenses

The R&M expenses approved by the Commission for the city based distribution licensees in the State of Maharashtra for the period from FY 2006-07 to FY 2009-10 has been analysed below.

Table 22: Net R&M Expenses of City based Distribution Licensees in Maharashtra

R&M Expenses **in Rs Crore**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
RInfra-D	103	134	141	148
TPC-D	5	6	7	7
BEST	44	26	27	29

The intra-State ratio analysis of various parameters on which the R&M expenses are dependent, viz., percentage of GFA, sales, and number of consumers, have been summarised below:

Table 23: Intra-State Ratio Analysis for benchmarking R&M Expenses

R&M Expense /unit **Rs/unit**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
RInfra-D	0.14	0.17	0.17	0.17	0.16
TPC-D	0.02	0.03	0.03	0.03	0.02
BEST	0.11	0.06	0.07	0.07	0.08

R&M Cost/consumer **Rs lakh /'000 Consumer**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
RInfra-D	4.11	4.99	5.17	5.29	4.89
TPC-D	20.96	26.66	23.94	20.94	23.13
BEST	4.61	2.75	2.84	2.94	3.28

R&M Expense /GFA **%**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
RInfra-D	5.37%	5.72%	5.81%	5.70%	5.6%
TPC-D	1.36%	1.59%	1.52%	1.44%	1.5%
BEST	4.01%	2.24%	2.19%	2.19%	2.7%

The inter-State ratio analysis of various parameters on which the R&M expenses are dependent, viz., sales, number of consumers, have been summarised below:

Table 24: Inter-State Ratio Analysis for benchmarking R&M Expenses

R&M expenses/unit Sales **Rs/unit**

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
CESC	0.10	0.11	0.12	0.13	0.12
BYPL	0.16	0.09	0.12	0.14	0.13
BRPL	0.12	0.11	0.13	0.14	0.13
NDPL	0.12	0.12	0.14	0.15	0.13
RInfra-D	0.14	0.17	0.17	0.17	0.16
TPC-D	0.02	0.03	0.03	0.03	0.02
BEST	0.11	0.06	0.07	0.07	0.08
TPL- Ahmd			0.15	0.15	0.15
TPL- Surat		0.10	0.09	0.09	0.09

R&M Expenses/Consumer **Rs Lakh /'000 consumer**

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
CESC	3.75	3.89	4.68	5.03	4.34
BYPL	4.92	3.33	4.14	5.01	4.35
BRPL	6.17	6.15	6.42	7.14	6.47
NDPL	6.53	6.23	7.04	7.69	6.87
RInfra-D	4.11	4.99	5.17	5.29	4.89
TPC-D	20.96	26.66	23.94	20.94	23.13
BEST	4.61	2.75	2.84	2.94	3.28
TPL- Ahmd			4.93	5.07	5.00
TPL- Surat		3.67	4.51	4.60	4.55

As seen from the above Tables:

- It will be difficult to benchmark the distribution licensees within Maharashtra based on comparison with each other.
- Intra-State comparison of various parameters, viz., sales and number of consumers for TPC-D would not be appropriate as its consumer mix and quantum of sales is not comparable with other distribution licensees. For TPC-D, better option could be benchmarking with its own performance. Hence, the

proposed norm for R&M expenses for TPC-D is 1.5% of opening GFA of the financial year.

- For RInfra-D and BEST, the normative R&M expenses have been determined based on inter-State comparison, as shown above. The proposed norm for R&M expenses for RInfra-D and BEST is 4% of opening GFA of the financial year.

6.5.2 Benchmarking of O&M expenses for MSEDCL (State based Distribution Licensee)

The O&M expenses approved by the Commission for MSEDCL (State based distribution licensee) for the period from FY 2006-07 to FY 2009-10 has been analysed below. Sales, number of consumers and GFA approved by the Commission, which is used for benchmarking purposes are tabulated below:

Table 25: O&M Expenses of MSEDCL (State based Distribution Licensee)

Rs Crore

	FY 2006-07	FY 2007-08	FY 2008-09
Employee Expenses	1,593	1,727	1,874
A&G Expenses	148	156	181
R&M Expenses	416	436	456
O&M Expenses	**2,157**	**2,319**	**2,511**

Rs Crore

	FY 2006-07	FY 2007-08	FY 2008-09
Sales (MU)	49,147	53,958	65,966
Consumers (Nos.)	14,655,250	12,177,809	16,809,590
GFA (Rs. Crore)	9428	10531	12565

The parameters on which the O&M expenses are dependent, viz., sales, number of employees, GFA, etc., have also been summarised in the above Table. The ratio analysis is given in the Table below:

Table 26: Ratio Analysis for MSEDCL for benchmarking O&M Expenses

in Rs/unit

	FY 2006-07	FY 2007-08	FY 2008-09	3 year-Average
Employee Expense/unit	0.32	0.32	0.28	0.31
A&G Expense /unit	0.03	0.03	0.03	0.03
R&M Expense /unit	0.08	0.08	0.07	0.08

O&M Cost/unit	0.44	0.43	0.38	0.42

Rs lakh /'000 Consumer

	FY 2006-07	FY 2007-08	FY 2008-09	4 year-Average
Employee Cost/'000 consumer	11	14	11	12.07
A&G Cost/'000 consumer	1.0	1.3	1.1	1.12
R&M Cost/'000 consumer	2.84	3.58	2.71	3.04
O&M Cost/'000 consumer	15	19	15	16.23

in %

	FY 2006-07	FY 2007-08	FY 2008-09	4 year-Average
R&M Expense /GFA (%)	4.42%	4.14%	3.63%	4.1%

The Electricity Regulatory Commissions (ERCs) of Andhra Pradesh, Karnataka and Rajasthan have approved consolidated O&M expenses and have not segregated it in terms of employee, A&G and R&M expenses. Hence, for inter-State comparison, consolidated O&M expenses of MSEDCL have been compared with other State Utilities to get a general understanding of benchmarking and then trifurcating it in terms of employee, A&G and R&M expenses. The ratio analysis is given in the Table below:

Table 27:Inter-State Ratio Analysis for benchmarking O&M Expenses

(Rs/Unit)

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
Andhra Pradesh					
APCPDCL	0.21	0.21	0.18	0.24	0.21
APEPDCL	0.29	0.28	0.25	0.34	0.29
APNPDCL	0.31	0.31	0.30	0.30	0.31
APSPDCL	0.31	0.30	0.28	0.32	0.30
Karnataka					
CESC-K	0.48	0.56	0.60	0.64	0.57
GESCOM	0.44	0.43	0.43	0.43	0.43
HESCOM	0.52	0.42	0.42	0.42	0.45
MESCOM	0.57	0.46	0.46	0.45	0.49
BESCOM	0.32	0.25	0.25	0.24	0.26
Gujarat					
PGVCL	0.36	0.34	0.33	0.31	0.33

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
DGVCL	0.15	0.16	0.20	0.19	0.18
UGVCL	0.25	0.23	0.30	0.28	0.27
MGVCL	0.41	0.42	0.55	0.51	0.47
Rajasthan					
Jaipur Discom	0.28	0.31	0.31		0.30
Ajmer Discom	0.29	0.31	0.32		0.31
Jodhpur Discom	0.27	0.24	0.26		0.26
MSEDCL	0.44	0.43	0.38		0.42

(Rs lakh/'000 consumers)

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
Andhra Pradesh					
APCPDCL	7.27	7.24	7.16	10.55	8.06
APEPDCL	6.28	6.13	6.17	8.72	6.82
APNPDCL	6.22	5.87	5.70	6.24	6.01
APSPDCL	5.96	5.52	5.41	6.65	5.89
Karnataka					
CESC-K	6.63	8.04	8.79	9.62	8.27
GESCOM	6.96	6.68	6.47	6.27	6.60
HESCOM	8.31	7.06	7.12	7.08	7.39
MESCOM	7.48	7.18	7.03	8.37	7.52
BESCOM	7.10	6.45	6.51	6.57	6.66
Gujarat					
PGVCL	9.65	11.06	10.61		7.83
DGVCL	7.11	7.07	9.66		5.96
UGVCL	10.34	10.50	13.59		8.61
MGVCL	9.38	9.58	14.55		8.38
Rajasthan					
Jaipur Discom	9.06	11.10	12.41		10.86
Ajmer Discom	10.89	12.27	13.57		12.24
Jodhpur Discom	9.85	10.35	11.97		10.73

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
MSEDCL	14.72	19.04	14.94		16.23

As seen from the above Tables, it is observed that:

- MSEDCL's O&M expenses have ranged around 42 paise per unit of sale and have been around Rs. 16.23 lakh per thousand consumers over the years.
- O&M expenses for MSEDCL are on the higher side, as compared to most of distribution licensees as shown in the Table above.
- Hence, the proposed norm for O&M expenses for MSEDCL is 35 paise per unit of sales.

Table 28: Inter-State Comparison of Employee expenses (Rs/unit)

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
Gujarat					
PGVCL	0.24	0.23	0.21	0.20	0.22
DGVCL	0.11	0.11	0.14	0.13	0.12
UGVCL	0.16	0.15	0.22	0.21	0.18
MGVCL	0.28	0.28	0.41	0.37	0.33
MSEDCL	0.32	0.32	0.28		0.31

Table 29:Inter-State Comparison of A&G expenses (Rs/unit)

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
Gujarat					
PGVCL	0.06	0.05	0.05	0.04	0.05
DGVCL	0.02	0.03	0.03	0.03	0.03
UGVCL	0.04	0.03	0.03	0.03	0.03
MGVCL	0.05	0.05	0.06	0.06	0.06
MSEDCL	0.03	0.03	0.03		0.03

Table 30:Inter-State Comparison of R&M expenses (Rs/unit)

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
Gujarat					
PGVCL	0.06	0.06	0.07	0.07	0.06
DGVCL	0.02	0.02	0.03	0.03	0.03
UGVCL	0.05	0.05	0.05	0.05	0.05
MGVCL	0.08	0.09	0.08	0.07	0.08
MSEDCL	0.08	0.08	0.07		0.08

As seen from the above Tables:

- MSEDCL's employee expenses have ranged around 31 paise per unit of sale over the years, as compared to less than 20 paise per unit for Gujarat Utilities.
- MSEDCL's A&G expenses have been around 3 paise per unit of sale, which is comparable to that of Gujarat Utilities.
- MSEDCL's R&M expenses have ranged between 3.63% and 4.42% of the opening Gross Fixed Assets (GFA) with an average of 4.1% of GFA.

Based on the above analysis, the following norms are proposed for determination of O&M expenses for MSEDCL:

(a)	Employee Expenses	:	25 paise per unit of sale
(b)	A&G Expenses	:	3 paise per unit of sale.
(c)	R&M Expenses	:	3.5% of opening GFA (which amounts to approximately 7 paise per unit of sale)

Further, capitalisation of O&M expenses should not be done on an ad-hoc basis, and the distribution licensees should ensure that proper accounting is done, so that only those O&M expenses incurred towards revenue items are booked under revenue expenditure, and O&M expenses of capital nature are capitalised.

6.6 Capital Expenditure

Distribution business is capital intensive in nature, requiring significant capital investment for meeting the electricity demand of existing and new consumers. The

Commission, under its MERC Guidelines for In-principle Clearance of Proposed Investment Schemes has specified the procedure for approval of investment plan of the distribution licensee.

These are Guidelines necessary to verify the prudence of capital investments made by Licensees for various purposes such as creation of new infrastructure to meet load growth, to meet statutory requirements, to strengthen the existing system and increase efficiency, etc. In addition to the MERC Tariff Regulations, the said Guidelines lay down certain procedures to ensure that capital investment schemes being proposed are necessary and justified, and do not impose an unnecessary burden on consumers by way of tariff.

The capital expenditure made by the distribution licensee has significant bearing on the ARR in the form of depreciation and Return on Capital Employed claimed for the new assets added. Therefore, all the investment proposed by the licensee requires to be checked for prudence by the Commission well before the actual expenditure is made.

It is essential that the Licensees should file the year-wise investment plan for the Control Period along with the MYT Petition for the second Control Period. The distribution licensee, while making the Investment Plan should give priority to schemes related to load growth, loss reduction and quality improvement. The licensee should address the following aspects while making the investment plan:

- The investment should be made in an economic and transparent manner
- Financial as well as social cost-benefit analysis should be done for all investment schemes
- All schemes having capital investment of more than Rs. 10 Crore should be submitted with detailed project report along with the investment plan.
- Investment plan shall also include the capitalisation schedule and financing plan.
- Once the capitalisation is achieved, the benefits actually accrued to the system should be captured and submitted to the Commission, in accordance with the Guidelines specified by the Commission.

It is proposed that Commission may approve the Investment Plan for the Control Period, taking into account the existing network conditions, expected load growth, etc., as part of the Order on MYT Petitions filed by the Distribution Licensees.

7 Norms and Principles for Determination of Revenue Requirement and Retail Tariff for Retail Supply Business

The retail supply tariff of a Distribution Licensee shall provide for the recovery of the aggregate revenue requirement of the Distribution Licensee for the financial year, as reduced by the amount of non-tariff income, income from wheeling, income from Other Business and receipts on account of cross-subsidy surcharge and additional surcharge, as approved by the Commission. The aggregate revenue requirement shall comprise the following: -

a) Cost of power generation / power purchase;

b) Transmission charges;

c) Return on Capital Employed: General principles have already been discussed earlier in Section-3 of this Approach Paper;

d) Depreciation: General principles have already been discussed earlier in Section-3 of this Approach Paper;

e) Operation and maintenance expenses;

f) Interest on working capital and deposits from consumers: General principles have already been discussed earlier in Section-3 of this Approach Paper;

g) Contribution to contingency reserves: General principles have already been discussed earlier in Section-2 of this Approach Paper.

h) Provisioning for bad debts: General principles have already been discussed earlier in Section-2 of this Approach Paper;

Minus:

i) Non-tariff income;

j) Income from Other Business;

k) Receipts on account of cross-subsidy surcharge; and

l) Receipts on account of additional surcharge on charges of wheeling.

7.1 *Long-term and Short-term Power Procurement*

The Distribution (Supply) Licensee purchases power from different sources either through long-term Power Purchase Agreements or through short-term contracts. The Commission under its MERC Tariff Regulations has specified the procedure for seeking approval for long-term and short-term power purchase contracts, based on the least cost principles with due consideration to power system stability, system voltage, frequency profile and system losses.

For effective implementation of the Multi Year Tariff Regime, it is important that the Licensees should prepare their long-term power procurement plan for the Control Period and submit the same to the Commission for approval. It is also important to establish the guidelines for long-term and short-term power procurement by Distribution Licensees. The proposed guidelines which may be stipulated in this regard are given below:

Long-term power procurement

The Distribution Licensee should prepare a five-year plan for procurement of power to serve the demand for electricity in its area of supply and submit such plan to the Commission for approval along with the MYT Petition. The long-term procurement plan should be prepared considering the:

- Quantitative forecast of the unrestricted demand for electricity, within the area of supply, from each tariff category over the plan period;
- An estimate of the quantities of electricity supply from the approved sources of generation and power purchase;
- Measures proposed to be implemented as regards energy conservation and energy efficiency;
- Minimum share of renewable energy percentage
- Requirement for new sources of power generation and/or procurement; and
- Cost estimates for power procurement.

Short-term power procurement

This issue has already been discussed earlier in Section-2 of this Approach Paper.

7.2 *Uniform vs Differential tariff*

Concerns have been raised by stakeholders and RInfra-D suggesting that the retail tariffs should be uniform across the city of Mumbai, irrespective of whether the consumer is being supplied by BEST, TPC-D or RInfra-D. The ground realities, legal provisions and complexities involved in the same are elaborated as under:

There are five distribution licensees in the State of Maharashtra, viz.,

Table 7: Distribution Licensees in the State of Maharashtra

Sl.	Distribution Licensee	Distribution Licence Area
1	Maharashtra State Electricity Distribution Company Limited (MSEDCL)	Entire State of Maharashtra, except licence area of TPC, BEST and RInfra-D, and including Kanjurmarg, Bhandup, and Mulund in Mumbai city
2	Reliance Infrastructure Limited – Distribution Business (RInfra-D)	From Sion to Kanjurmarg in Central suburbs and from Mahim to Mira-Bhayander in Western suburbs
3	Brihan-Mumbai Electricity Supply & Transport Undertaking (BEST)	Bombay City district, from Colaba to Sion and Mahim
4	The Tata Power Company – Distribution Business (TPC-D)	Overlap with both RInfra-D and BEST licence area
5	The Mula Pravara Electric Co-operative Society Limited (MPECS)	3 Talukas of Ahmednagar District, viz., Rahata, Shrirampur, and Rahuri

Though the EA 2003 permits differentiation between similarly placed consumers, in Maharashtra, the Commission through its Tariff Orders has attempted to minimize the tariff differential across different licence areas, which has been possible to a limited extent. For instance, in the city of Mumbai, BEST has the distribution licence in Bombay City District, viz., from South Mumbai to Mahim and Sion, whereas RInfra-D has the distribution licence in suburban Mumbai. Also, MSEDCL, the successor Company of erstwhile MSEB, supplies electricity to parts of Bhandup and Mulund, which are a part of Mumbai city. The category-wise tariff for different consumer categories in each of the licence areas has always been different (except in case of MPECS, which used to earlier supply electricity at the same tariffs as charged by MSEDCL), due to reasons of difference in the cost of supply, consumer mix, consumption mix, etc., and it is difficult to have an uniform Retail Supply Tariff in the State across all licensees.

The cost of supply depends upon various factors such as cost of power procured, distribution losses, operational and administrative expenses, capital related expenditure such as depreciation and interest, etc., which is bound to vary between different licensees, due to inherent differences in power purchase mix, availability and cost of own generation, operational efficiency in controlling distribution losses, and, therefore, it is practically not possible to determine uniform Retail Supply Tariff in the State across all licensees. The Commission considers respective cost of supply and consumption mix to determine the category-wise tariffs for different licensees. Further, Section 62(3) of the EA 2003 permits the Commission to differentiate between consumers even within the same licence area on certain grounds, which is obviously applicable to consumers residing in different licence areas.

The Electricity Act, 2003 (EA 2003) vests the Commission with the statutory powers to regulate the electricity industry with the object of ensuring consumer protection. In determining the category-wise tariffs, the Commission has been guided by the principle that consumer tariffs should reflect the cost of supply. The Tariff Policy notified by the Ministry of Power, Government of India, stipulates as under:

"8.4 Definition of tariff components and their applicability

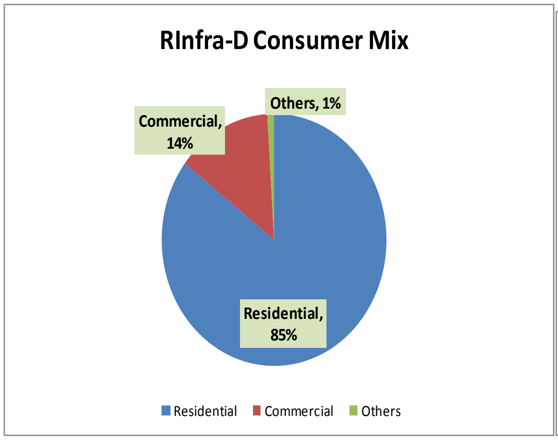
> *…*
>
> *2. The National Electricity Policy states that existing PPAs with the generating companies would need to be suitably assigned to the successor distribution companies. The State Governments may make such assignments taking care of different load profiles of the distribution companies so that retail tariffs are uniform in the State for different categories of consumers. Thereafter* ***the retail tariffs would reflect the relative efficiency of distribution companies in procuring power at competitive costs, controlling theft and reducing other distribution losses****." (emphasis added)*

All distribution licensees in the State of Maharashtra have to apply to the Commission for approval of their Aggregate Revenue Requirement (ARR) and category-wise tariffs. The Commission scrutinizes the Petition and data and the data deficiencies, if any, are communicated to the distribution licensee. Subsequently, a Technical Validation Session is conducted by the Commission in the presence of the authorised Consumer Representatives, in which additional data is requested from the distribution licensee, if required. The distribution licensee has to submit the revised Petition along with additional data to the Commission, after which the Commission admits the Petition for hearing the matter. Thereafter, the distribution licensee has to publish a Public Notice in the leading newspapers, communicating to all the stakeholders, the salient features of the Petition and proposed tariffs, as well as make available copies of the Petition and Executive Summary at head office and divisional offices, to enable interested stakeholders to submit their comments/suggestions/objections to the Commission within the stipulated period of normally three weeks. The Commission then conducts Public Hearing/s in the matter to give an opportunity to interested stakeholders to present their comments/suggestions/objections before the Commission. All the objections/comments/suggestions submitted by the stakeholders, and the replies filed by the distribution licensee are considered by the Commission before issuing the Tariff Orders.

The tariff philosophy adopted by the Commission as enunciated in the Commission's various Tariff Orders, are:

1 Reflection of Cost of Supply
2 Prudency of Costs
3 Introduction of two-part tariff for all consumer categories
4 Increase in recovery of fixed costs through fixed charges
5 Reduction of cross-subsidy
6 Rationalization of tariff categories, guided by principles of -
    - Simplicity
    - Targeting of subsidy
    - Time of Use Tariff

The following Graphs provides the comparative data of consumption mix and consumer mix of BEST and RInfra-D, as an illustration:



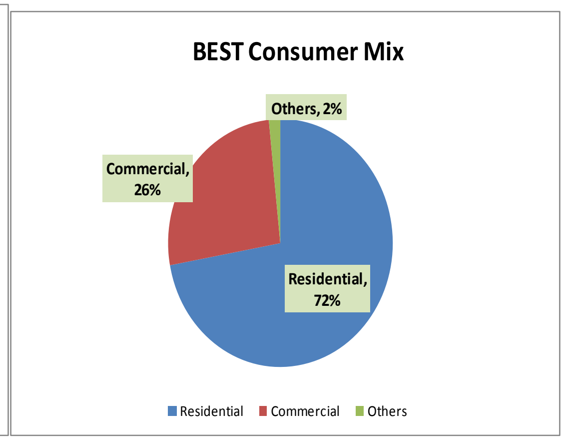
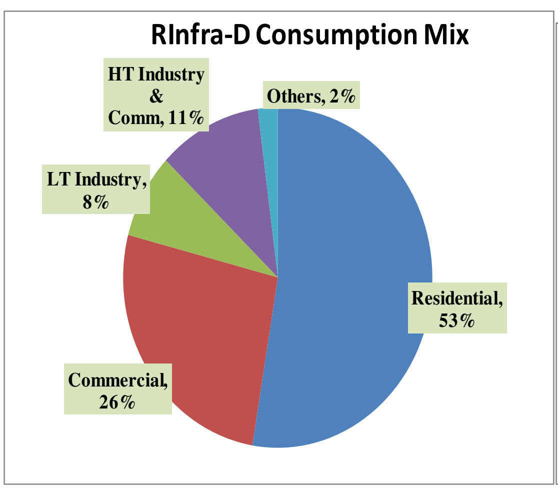


Figure 1: Comparison of Consumer Mix of RInfra-D and BEST

It may be noted that BEST has a significantly higher proportion of commercial consumers and commercial consumption as compared to that of RInfra-D, while RInfra-D has a higher proportion of residential consumers, which enables BEST to cross-subsidise its domestic consumers at the expense of the commercial consumers to a larger extent, which is not possible to the same extent in RInfra-D area. Further, as seen in the Graphs below, the consumption mix of BEST is more favourable than that of RInfra-D, as it has a higher proportion of subsidising consumers, primarily commercial consumption, where the tariffs are higher.



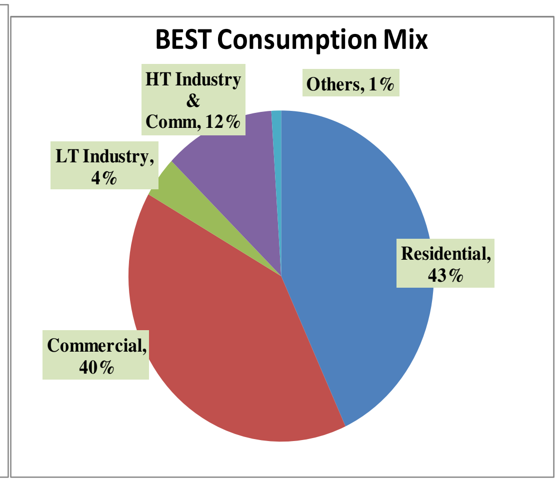


Figure 2: Comparison of Consumption Mix of RInfra-D and BEST

The above analysis shows that any comparison of tariffs between different licence areas has to be seen in the context of the cost of supply, the consumer mix, consumption mix, current level of cross-subsidy, and other factors.

It may also be noted that the **Forum of Regulators**, a statutory authority under the Electricity Act, 2003, has recommended as under:

> *"15. The proposition of keeping tariffs at the same level in the areas of different licensees in a State is not in accordance with EA 2003 and the Tariff Policy. Differential tariff structure in the area of different licensees in a State should be considered and the tariffs should reflect the efficiencies achieved by a particular licensee and also allocate the PPAs and Capacity of State Generating Stations in different proportions to different licensees.*
>
> *16. Tariff design for various consumer categories should be based on average cost of supply as this is the most common method and has also been envisaged in the Tariff Policy in the context of reduction of cross-subsidy"*

As regards the comparison with the uniform tariffs being levied in other States, viz., Delhi, AP, Karnataka, etc., the following needs to be considered:

There are broadly four types of States, as under:

1. States, where the State Electricity Board (SEB) continues to operate as the vertically integrated Utility even now (TN, Bihar, HP, Kerala, etc.)
2. States, where the SEB has been unbundled and successor Distribution Company/ies have been created, but DISCOMs have not been privatised (Karnataka, AP, MP, Rajasthan, etc.)
3. States, where the successor Distribution Licensees have been privatised (Orissa & Delhi)
4. States, where private Distribution Licensees (Schedule VI Licensees) have been in existence even before the SEB's were created (Gujarat, Maharashtra, and West Bengal)

In **Type (1) States**, the same distribution licensee is supplying electricity to the entire State, and the tariff is obviously same for any consumer category across the State.

In **Type (2) States**, though different distribution licensees are supplying electricity to the entire State, the tariff is determined such that the tariff is same for any consumer category across the State. This is managed by providing differential Government subsidy to the distribution licensees, so that the revenue requirement is met, despite the differential consumption mix, efficiency levels, etc. Thus, the State Governments rather than the SERCs are ensuring that the tariffs are same across the State. This method is precisely what has been suggested by the Forum of Regulators in its recent recommendation, in case the State Government desires to ensure uniform tariffs across the State.

In **Type (3) States**, the SERC has determined uniform tariffs. In Delhi, as part of the privatisation process, the Government of National Capital Territory of Delhi (GNCTD) had notified 'Policy Directions' for a period of five years, which were valid till FY 2007-08 (March 31, 2008). The Policy Directions stipulated that the tariffs should be uniform in the State, and the GNCTD subsidy support should be adjusted in such a manner that the retail tariff are uniform. In one of the years, when NDPL's performance was very good, DERC amortised the Regulatory Asset created for NDPL at a faster rate, in order that the benefit of NDPL's better performance was passed on to its consumers. However, after the end of the Policy Direction period, there is no binding policy on DERC to determine uniform retail tariffs.

More importantly, DERC has determined differential tariffs for the licence area of New Delhi Municipal Council (NDMC), which is the area of Central Delhi, including Connaught Place, Parliament, etc. The tariff structure and category-wise tariffs of NDMC are totally different as compared to that applicable in the licence areas of BRPL, BYPL and NDPL. Hence, it cannot be said that the tariffs are uniform in the city of New Delhi.

However, in the latest Tariff Orders DERC has determined uniform tariffs for BRPL, BYPL and NDPL, in accordance with Clause 8.4(2) of the Tariff Policy, which stipulates that the Power Purchase Agreements may be allocated in such a manner that the tariffs are uniform across different licence areas, after which the retail tariffs would reflect the relative efficiency of distribution companies in procuring power at competitive costs, controlling theft and reducing other distribution losses. Moreover, under the approach being followed in Delhi, the tariffs are determined in such a manner that the distribution licensee with the highest revenue gap (i.e., BYPL) is able to meet its revenue gap. As a result, distribution licensees having a lower revenue gap (or even revenue surplus, as was the case for NDPL and BRPL) are able to earn additional revenue, which is over and above their approved revenue requirement. This surplus is designed to be retained by the concerned distribution licensee but parked in a separate reserve/fund called MYT Contingency Reserve at a later stage. Thus, the benefit of the additional surplus will have to be passed on to the consumers of the concerned distribution licensee, which will eventually result in differential tariffs for the consumer categories across different distribution licensees, viz., NDPL, BRPL and BYPL.

In **Type (4) States**, which include Maharashtra, Gujarat, and West Bengal the tariffs charged by different distribution licensees in Mumbai city, Ahmedabad and Surat city, and Kolkata city, respectively, have always been different as compared to that chargeable in the rest of the State, and continue to be different, even after the SERCs have been established, for reasons elaborated above.

Further, if uniform tariffs are determined across distribution licensees, it will amount to consumers of one licensee being subsidised by consumers in other licence areas, as these consumers will have to pay for the high costs of the first licensee, though they are served by other distribution licensees.

Moreover, the focus of the EA 2003 is on decentralisation and creation of more competition through open access and parallel licensees and franchisees, in order to encourage efficiency improvement. It is obvious that the expenses of each licensee will be different and hence, tariffs will also be different, to reflect the efficiency and the cost structure of the concerned distribution licensee.

Further, if at all uniform tariffs are to be considered, then why should tariffs be uniform only in the city of Mumbai rather than being uniform in the entire State of Maharashtra, as is the case in several States? This argument could be stretched further to consumers located in border areas of the State, who frequently submit that tariff in neighbouring States/Union Territories (UTs) such as Madhya Pradesh, Chhattisgarh, Daman and Diu, etc., are lower, which is affecting their competitiveness, and hence, their tariffs should be reduced. There are requests from other regions also that the tariffs should be determined on a region-wise basis.

Moreover, the city of Mumbai includes areas of Kanjurmarg, Bhandup and Mulund, which are part of the licence area of MSEDCL. If the retail tariffs in the city of Mumbai are to be made uniform, it would effectively mean that the tariffs of all licensees in the State will have to be uniform, since there cannot be any differentiation for the same category of consumer across different areas of MSEDCL licence area. Also, consumers in Kanjurmarg, Bhandup and Mulund are subjected to load shedding, which is not the case with consumers supplied by other Mumbai licensees. On the other hand, Mumbai licensees are paying standby charges of around Rs. 400 crore every year to MSEDCL to mitigate the threat of load shedding due to outages in their system. This revenue is being used to reduce the tariffs in MSEDCL licence area. Hence, this is a very complex matter and there is no easy solution available. Any such dispensation has to consider all these aspects.

From the above, it is clear that if uniform tariff has to be introduced and cross-subsidy has to be retained at the existing levels or increased further, then the EA 2003 and the Tariff Policy may have to be amended, or the State Government may have to provide subsidy to the concerned distribution licensees to compensate for the loss of revenue, since the tariffs for any category would then have to be retained at the lowest level applicable amongst the distribution licensees

7.3 Basis of Fixed Charge Recovery

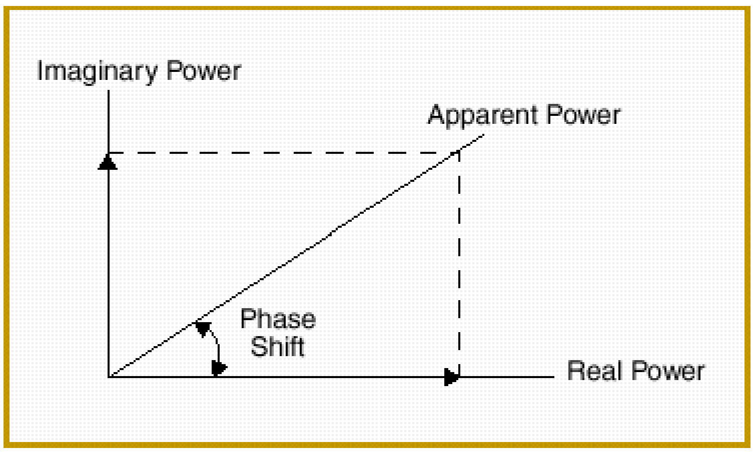
The Commission has specified the following basis for fixed cost recovery:

1. LT Categories – Fixed amount per service connection or based on sanctioned load in HP or kW, wherever sanctioned load data is reliable
2. HT categories – on the basis of Contract Demand in kVA

The above approach is appropriate in view of the data limitations. Ideally, the fixed charge recovery should be linked to the load imposed on the system, which is best represented by the Contract Demand in kVA. In cases where there is no Contracted Demand, the sanctioned/connected load may be used to determine the Fixed Charges, in Rs/kW. However, for certain LT categories such as residential and non-residential or commercial, the experience is that the sanctioned/connected load data is not reliable, and may not be an appropriate parameter for levy of fixed charges. However, once the Wires business is unbundled from the Retail Supply business, fixed charges for retail consumers may be linked to the fixed costs associated with Retail Supply business. It is proposed that the fixed charges determined for each customer category shall be kept at same level during the Control Period, and only Energy Charges will vary in accordance with RPI-X+Z mechanism.

7.4 *Basis of Energy Charge – Rs/kWh or Rs/kVAh*

Energy charges are levied on actual energy consumed by the licensee's consumers. Here, the issue is whether the energy charges should be levied in terms of real energy consumption (expressed in kWh terms) or apparent energy consumption (expressed in kVAh terms). The relationship between the real and apparent energy consumption is governed by the following relationship:



From the above figure, it is clear that the requirement of power will be higher if the load is inductive in nature. Therefore, the energy requirement for inductive load will be higher as compared to that for resistive load.

Domestic and commercial category consumers have high lighting load, i.e., mainly resistive load. In industrial category, there is significant inductive load in the form of motors, pumps, etc., therefore, for industrial category, the kVAh consumption will be higher than kWh consumption due to the requirement of significant amount of reactive power.

The energy charges could be levied on the basis of total energy required by the consumer for meeting its requirement, thereby, taking into consideration real power as well as reactive power. Energy charge for the domestic and commercial category could be determined on real power basis (or Rs/kWh basis) while for industrial consumers, the energy charge could be levied on apparent power basis (or Rs/kVAh basis). Alternatively, the mechanism of offering power factor incentive/penalty may be adopted, as is the current practice.

Reactive energy charges and power factor penalty/incentive are two different methods of achieving the objective of enforcing voltage discipline in the distribution system. The distribution system often faces the problem of erratic voltage, due to high reactive power consumption. For mitigating the above irregularities and encouraging the consumers for better management of distribution system, the provision of reactive energy charges or power factor penalty/incentive needs to be in place.

The present tariff structure provides for levy of power factor penalty and incentives for HT category, LT Industry, LT Public Water Works and LT Non-residential (load above 20kW) category consumers, wherein the consumers have to maintain a minimum power factor of 0.90.

<u>Power Factor (PF) Incentive</u>

An incentive is presently given at the rate of 1% (one percent) of the amount of the monthly bill including energy charges, FAC, and Fixed/Demand Charges, but excluding Taxes and Duties for every 1% (one percent) improvement in the power factor (PF) above 0.95. For PF of 0.99, the effective incentive amounts to 5% (five percent) reduction in the monthly bill and for unity PF, the effective incentive amounts to 7% (seven percent) reduction in the monthly bill.

<u>Power Factor Penalty</u>

Penalty is levied on consumer categories mentioned above if average power factor falls below 0.90, @ 2% of the amount of the monthly bill including energy charges, FAC, and Fixed/Demand Charges, but excluding Taxes and Duties for the first 1% (one percent) fall in the power factor below 0.9, beyond which the penal charges is levied at the rate of 1% (one percent) for each percentage point fall in the PF below 0.89.

The prevailing mechanism of power factor incentive/penalty is being practiced in quite a few other States as well, and has yielded good results. Hence, it is proposed that the existing power factor incentive/penalty mechanism should be continued.

7.5 Time of Day (TOD) Tariff

The system demand during different hours of the day varies significantly. Quite often, the demand during peak hours is much higher than the demand at off-peak hours.

Under such circumstances, the licensee as well as the Generation Company is required to build the distribution infrastructure and generation capacity, respectively, to cater to the demand during the peak hours. Since the demand is lower during off-peak hours, it results in reducing the capacity utilisation factor, as well as overloading of transmission and distribution network, and to some extent increases the distribution losses in the system.

Ideally, the Utilities would prefer to have a flat load curve during the entire day, as this would reduce the capital investment required, and would also ensure very high capacity utilisation factors. However, this is not practicable, since the consumption pattern of different consumer categories is quite different, and different categories impose different loads on the system during different hours of the day. However, it is possible to reduce the differential between the demand existing during peak hours and that existing during off-peak hours. For reducing the difference between peak and off-peak demand, the concept of Time of Day (ToD) charges has been successfully introduced in several other States. Under this approach, additional TOD charges (in addition to base energy charges) are levied on energy consumed during the peak hours, and a rebate is given on energy consumed during the off-peak hours. Differential pricing, according to the time of day, incentivises the users to shift their demand from peak demand periods to the off-peak period. This is a tried and tested approach to flatten the load curve. However, it has to be borne in mind that it is quite possible that the demand of the categories primarily contributing to the peak demand is inelastic and cannot be shifted to off-peak hours, in which case, the ToD tariffs will have to be levied on the consumer categories, such as industrial consumers, who can actually shift their consumption to off-peak hours. However, for designing the ToD tariffs, it would be required to have an idea of the system load curve, as well as preferably the category-wise load curves for representative days of the year. The extent of tariff differential between peak and off-peak hours also needs to be deliberated upon.

The National Electricity Policy has also emphasized on introduction of TOD tariffs for reducing the requirement of fresh capacity addition by reducing the gap between the peak and off-peak demand. The relevant text of Clause 5.9.6 of National Electricity Policy is reproduced below:

> *"In order to reduce the requirements for capacity additions, the difference between electrical power demand during peak periods and off-peak periods would have to be reduced. Suitable load management techniques should be adopted for this purpose.*

Differential tariff structure for peak and off peak supply and metering arrangements (Time of Day metering) should be conducive to load management objectives. ..."

The Tariff Policy notified by the Government of India has also emphasized on introduction of TOD tariffs for facilitating flattening of the peak demand. Clause 8.4 of the Tariff Policy stipulates,

"1. Two-part tariffs featuring separate fixed and variable charges and Time differentiated tariff shall be introduced on priority for large consumers (say, consumers with demand exceeding 1 MW) within one year. This would also help in flattening the peak and implementing various energy conservation measures."

The prevailing mechanism of TOD tariff being practiced in Maharashtra has yielded good results. Hence, it is proposed that the existing ToD tariff mechanism be continued. The State Load Despatch Centre is mandated with undertaking scheduling and despatch of load and supply in the State in a manner so as to ensure optimisation of the costs and ensuring that the maximum demand is met, by undertaking merit order despatch of all generation sources at their disposal. Hence, while designing the ToD tariffs, the peak and off-peak hours for the State system as a whole has to be considered, rather than the peak and off-peak hour of the individual distribution licensee.

7.6 Rationalisation of Tariff Categories

As discussed in Section-2 of this Approach Paper, it is not feasible to have uniform tariffs across different licensees due to inherent differences, such as revenue requirement, consumer mix, consumption mix, LT:HT ratio, etc. It is also, not appropriate to compare category-wise tariffs across different licensees for the same reasons. However, it is important to gradually rationalise and make uniform the tariff categorisation and applicability of tariffs for licensees in the State of Maharashtra. The differences exist because of historical reasons and differences in management policies and approach across licensees. There will of course, be some differences, on account of certain consumer categories being present only in certain licence areas, such as agricultural category, etc., which will exist only in certain licence areas.

At the same time, it needs to be ensured that the changes due to rationalisation are such that the impact on consumer categories is minimised, to the extent possible, and also, that the modifications are undertaken in small incremental steps, rather than making sudden changes to the tariff structure. Also, the fact that the consumers may not be aware of the modifications proposed to be undertaken by the Commission has also to be kept in mind, in view of certain Judgments given by the Appellate Tribunal of Electricity (ATE) in this regard, though the ATE has also ruled that the Commission has all the powers to determine the tariff categories and category-wise tariffs, irrespective of whether the distribution licensee has specifically asked for the same in its Petition, which has been published for public comments. Hence, by and large, the categorisation has been retained by the Commission in accordance with the prevailing consumer categories, save for any rationalisation required on account of differences prevailing in different licence areas, and in case the licensee has specifically asked for any category, the Commission has also considered the same in accordance with the provisions of Section 62(3) of the EA 2003.

Section 62(3) of the Electricity Act, 2003, stipulates as under:

> *"The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity 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."*

It should be noted that it is not possible to apply all the above specified criteria at the same time, for designing the tariff categories; else, with many permutations and combinations, there will be too many categories. Perhaps, that is also not the intention behind the provision, which merely enables the Regulators to work within the criteria. Uniform tariff categorisation would also be essential, in case of distribution open access.

It will be seen from the elucidation given below, as to how different criteria have been used to categorise different types of consumers:

- The 'load factor' and 'power factor' criteria have been used to provide rebates and disincentives, such as load factor incentive for load factor above certain specified levels, and power factor rebates and disincentives are provided to consumers who are able to maintain their power factor above specified levels.

- The consumer categories are broadly classified under High Tension (HT) and Low Tension (LT) categories, in accordance with the 'voltage' criteria under Section 62(3) reproduced above.
- The 'time of supply' criteria has been used to specify time of day (ToD) tariffs, so that the consumers are incentivised to shift their consumption to off-peak periods and thus, reduce the burden on the system during peak hours.
- The 'nature' of supply criteria has been used to specify differential tariff for continuous (non-interruptible) and non-continuous supply (interruptible)
- The criteria of 'purpose' of supply has been used extensively to differentiate between consumer categories, with categories such as residential, non-residential/commercial purposes, industrial purpose, agricultural purpose, street lighting purpose, etc.

While the Commission has by and large ensured reasonably uniform tariff categorisation for all distribution licensees in the State, it is proposed that the Commission may try to ensure complete uniformity in tariff categorisation for the second Control Period.

In its recent Tariff Orders, the Commission has also stated its intention to undertake the following tariff categorisation changes, and has also clarified as under:

> *"In this context, quite a few consumers have been representing before the Commission during and after the Public Hearings, stating that they are not undertaking any 'commercial' activity or activities for making 'profit' within their premises, and hence, they should not be classified under the 'commercial' category. It is clarified that the 'commercial' category actually refers to all 'non-residential, non-industrial' purpose, or which has not been classified under any other specific category. For instance, all office establishments (whether Government or private), hospitals, educational institutions, airports, bus-stands, multiplexes, shopping malls, small and big stores, automobile showrooms, etc., are all covered under this categorisation. Clearly, they cannot be termed as residential or industrial. In order to bring clarity in this regard, the Commission has renamed this category as 'non-residential or commercial' in this Order.*
>
> *A similar impression is conveyed as regards the 'Industry' categorisation, with the Commission receiving several representations during and after the Public Hearings, from*

the hotel industry, leisure and travel industry, etc., stating that they have also been classified as 'industry' for the purpose of taxation and/or other benefits being extended by the Central Government or State Government, and hence, they should also be classified as 'industry' for the purpose of tariff determination. In this regards, it is clarified that classification under Industry for tax purposes and other purposes by the Central or State Government shall apply to matters within their jurisdiction and have no bearing on the tariffs determined by the Commission under the EA 2003, and the import of the categorisation under Industry under other specific laws cannot be applied to seek relief under other statutes. Broadly, the categorisation of 'Industry' is applicable to such activities, which entail 'manufacture'.

While appreciating the anxiety of different classes of consumers to reduce their payments on account of use of electricity, the reasonable costs incurred by the Utilities have to be met, and irrespective of the number of consumer categories or the sub-classification considered in accordance with the provisions of Section 62(3) of the EA 2003, the cross-subsidies have to be reduced gradually and the tariff differential between categories cannot be very significant in the long-run."

…

"The tariff differential between HT Industry and HT Railways has been eliminated, with the objective of eventually bringing them under a single category."

7.7 Cross Subsidy Surcharge

The cross-subsidy surcharge for eligible open access consumers in the State of Maharashtra will have to continue to be zero, since the opening level of cross-subsidy surcharge computed in accordance with the formula stipulated by the Tariff Policy, works out to be negative, in view of the high prices of marginal power purchase.

7.8 Fuel Surcharge Adjustment

Regulation 82 of MERC Tariff Regulations, 2005 stipulates that

"82 Fuel surcharge adjustment

82.1 With effect from the first day of September, 2005, the Distribution Licensee shall pass on adjustments, due to changes in the cost of power generation and power procured *due to changes in fuel cost, through the Fuel Adjustment Cost (FAC) formula, as specified below.*

82.2 The FAC charge shall be applicable on the entire sale of the Distribution Licensee without any exemption to any consumer.

82.3 The FAC charge shall be computed and charged on the basis of actual variation in fuel costs relating to power generated from own generation stations and power procured during any month subsequent to such costs being incurred, in accordance with these Regulations, and shall not be computed on the basis of estimated or expected variations in fuel costs.

82.4 The Distribution Licensee shall submit details in the stipulated format to the Commission on a quarterly basis for the FAC charged and, for this purpose, shall submit such details of the FAC incurred and the FAC charged to all consumers for each month in such quarter, along with the detailed computations and supporting documents as may be required for verification by the Commission:

Provided that where the FAC is being charged for the first time subsequent to the notification of these Regulations, the Distribution Licensee shall obtain the approval of the Commission prior to levying the FAC charge:

Provided further that the FAC charge applicable to each tariff category of consumers shall be displayed prominently at the cash collection centres and on the internet website of the Distribution Licensee:

Provided that the Distribution Licensee shall put up on his internet website such details of the FAC incurred and the FAC charged to all consumers for each month along with detailed computations.

82.5 The formula for the calculation of the FAC shall be as given under:

FAC (Rs crores) = ***C + I + B****, Where*

FAC = Fuel Adjustment Cost

C *= Change in cost of own generation and power purchase due to variation in the fuel cost*

***I** = Interest on working capital*

***B** = Adjustment factor for over-recovery / under-recovery*

*Explanation I – for the purpose of this Regulation 82.5, the term **"C"** shall be computed in accordance with the following formula:*

C (Rs. Crores) = AFC,Gen + AFC,PP, Where:

AFC,Gen : Change in fuel cost of own generation. T his change would be computed based on the norms and directives of the Commission, including heat rate, auxiliary consumption, generation and power purchase mix, etc.

AFC,PP : Change in energy charges of power procured from other sources. This change would be allowed to the extent it satisfies the criteria prescribed in these Regulations and the prevailing tariff order, and subject to applicable norms.

*Explanation II – for the purpose of this Regulation 82.5, the term **"I"** shall mean change in interest on working capital on account of change in fuel cost.*

*Explanation III – for the purpose of this Regulation 82.5, the term **"B"** shall be computed in accordance with the following formula:*

BJ-2 (Rs. Crores) = AJ-4 + RJ-2

Where:

AJ-4 : Incremental cost in month "J-4".

RJ-2 : Incremental cost in month "J-4" actually recovered in month "J-2".

*82.6 The **monthly FAC charge shall not exceed 10% of the variable component of tariff, or such other ceiling as may be stipulated by the Commission from time to time: Provided that any excess in the FAC charge over the above ceiling shall be carried forward by the Distribution Licensee and shall be recovered over such future period as may be directed by the Commission.***

82.7 The calculation for FAC to be charged for the month "J" shall be as follows:

FAC (Rs crores) = CJ-2 + I J-2 + BJ-2

The FAC would be applicable from the month following the month in which the additional costs are calculated.

82.8 The FAC charge shall be allowed only in respect of approved power purchases of the Distribution Licensee and in respect of power purchases made in accordance with Regulation 25 where the approval of the Commission is not required under these Regulations.

82.9 The total FAC recoverable, as per the formula specified above, shall be recovered from the actual sales in "Rupees per kilowatt-hour" terms:

Provided that in case of unmetered consumers, FAC shall be recoverable based on estimated sales to such consumers, calculated in accordance with such methodology as may be stipulated by the Commission:

Provided further that where the actual distribution losses of the Distribution Licensee exceed the level approved by the Commission, the amount of FAC corresponding to the excess distribution losses (in kWh terms) shall be deducted from the total FAC recoverable.

82.10 Calculation of FAC per kWh shall be as per the following formula:

*FACRs./kWh = (FAC / (Metered sales + Unmetered consumption estimates + Excess distribution losses)) * 10"*

For the second Control Period, FAC shall form part of 'Z' factor and would be pass through to the consumers on a quarterly basis, subject to prudence check. The prevailing mechanism of FAC computation and cap of 10 percent of the variable component being practiced in Maharashtra has yielded good results. Hence, it is proposed that the existing FAC mechanism for Supply Business shall be continued.

8 Norms and Principles for Energy Efficiency (EE) and Demand Side Management (DSM)

8.1 Introduction to Demand Side Management (DSM)

While several definitions have been used to describe DSM, the broad range of activities that are generally undertaken by Utilities as DSM can be described as a set of initiatives undertaken by the Utility on the consumer side of the 'meter' to bring about the desired change in consumer demand and/or demand profile while maintaining or even enhancing the quality of service provided to the consumer in terms of quality, reliability and cost of service. It is important to note the emphasis on 'Utility initiatives' or 'Utility organized' efforts and that too on the 'consumer side of the meter'. It is a partnership between the Utility and the customer for mutual benefit. Demand Side options involve reducing the demand for electricity by implementing suitable DSM initiatives that call for adoption of Energy Conservation (EC) and Energy Efficiency (EE) for improving measures and practices by consumers of electricity that result in saving of electricity and reducing demand for electricity. Since, electricity saved is better than electricity generated or purchased, any savings in electricity consumption or demand as a result of DSM initiatives, directly contributes to balancing the electricity demand-supply equation. The following table depicts the benefits of any DSM programme to various stakeholders:

Parameter	Stake Holder		
	Customer	**Society**	**Utility**
Cost	Lower bills	Reduced debt	Lower cost of service
Quality	Improved service	Improved service	Improved customer service
Capital expenditure	Non-energy business benefits	Lower business costs, capital freed for other projects	Less generation and network capacity required
Environment	Reduced pollution	Reduced pollution	Improved operating efficiency
Corporate Sustainability Reporting		Conservation of indigenous energy resources	

DSM offers Utilities an opportunity to address several operational and management issues, such as improvement of power quality and reliability, reduction in system losses, easing network constraints, etc. DSM is feasible in situations where the cost of DSM is lower than the marginal cost of supply. In India, though per capita availability of energy is very low, in absolute terms, energy consumption is quite high. As a result, India is facing a problem of meeting the energy requirement with available resources. Therefore, DSM can be utilised to support the Utilities' efforts to mitigate power shortages.

8.2 Relevant Legal and Policy Provisions for DSM/EE in India

8.2.1 Energy Conservation Act 2001 (EC Act 2001)

The first policy initiative in India to coordinate various activities associated with efficient use of energy and its conservation was undertaken through enactment of the EC Act 2001. The EC Act 2001 was enacted in October 2001 to provide for efficient use of energy and its conservation and for matters connected therewith. The EC Act 2001 provides the legal mandate for the implementation of energy efficiency measures to the Central and the State Government through the institutions of Bureau of Energy Efficiency (BEE) and State Designated Agency (SDA).

The powers of BEE, Central Government and State Governments have been explicitly specified in the EC Act 2001. The primary focus of the EC Act 2001 is on setting minimum energy standards for, and affixing energy-consumption labels on appliances and equipment, promulgation of Energy Conservation Building Codes (ECBC), Energy consumption norms for Designated Consumers, dissemination of information and best practices, Capacity Building, establish EE delivery systems through Public-Private Partnership and consumer awareness among others.

Powers entrusted with the State Government includes powers to amend energy conservation building codes to suit regional and local climatic conditions, take measures to create awareness and disseminate information for efficient use of energy and its conservation, take steps to encourage preferential treatment for use of energy efficient equipment or appliances, and direct 'designated consumers' to comply with efficiency standards, among others.

BEE has initiated various EE and DSM measures including CFL programmes in States (Bachat Lamp Yojna), Standards and Labelling program, Energy Efficiency programmes in existing buildings, Energy Conservation Building Codes (ECBC), Capacity building of SDAs and implementation of various other provisions of the EC Act, 2001.

The EC Act 2001 provides for various legal and penal provisions, but the same have not being invoked as of now. The EC Act 2001 does not place responsibility on distribution companies (DISCOMs) other than the fact that the DISCOMs are designated consumers and are required to improve efficiencies in their operations. However, it is now being realised that a significant potential of savings through energy efficiency can be realised through DSM. Also, the future success of DSM would be driven by the support of Regulators. Regulators will have to incorporate provisions that would provide incentives for utilities to promote DSM. As a result of this, BEE is also promoting DSM in agriculture, municipality and Small and Medium Enterprises (SMEs), DSM by Distribution Companies and capacity building program of Regulators and Distribution Companies.

8.2.2 Electricity Act 2003 (EA 2003)

Optimal utilization of electricity has been the key theme of the Electricity Act, 2003 (EA 2003) as is evident from the Preamble to the EA 2003, as reproduced below:

> *"…. 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, rationalization of electricity tariff, ensuring transparent policies regarding subsidies, promotion of efficient and environmentally benign policies….".(emphasis added)*

The preamble to the EA 2003 clearly specifies 'efficiency' and 'promotion of environmentally benign policies' as one of the key objectives of the EA 2003. The following Sections of the EA 2003 translate these objectives stated in the preamble into operative provisions:

- Section 23 (Direction to Licensees)
  - *"If the Appropriate Commission is of the opinion that it is necessary or expedient so to do for maintaining the efficient supply, securing the equitable distribution of electricity and promoting competition, it may, by order, provide for regulating supply, distribution, consumption or use thereof." (emphasis added)*

- Section 30 (Transmission within a State)
  - *"The State Commission shall facilitate and promote transmission, wheeling and inter-connection arrangements within its territorial jurisdiction for the <u>transmission and supply of electricity by economical and efficient utilisation of the electricity</u>." (<u>emphasis added</u>)*

- Section 38 2(c) (CTU and functions)
  - *"to ensure development of an efficient, co-ordinated and economical system of inter-State transmission lines for smooth flow of electricity from generating stations to the load centres"*

- Section 42 (1) (Duties of Distribution Licensees and OA)
  - *"it shall be the duty of a distribution licensee to develop and maintain an efficient, co-ordinated and economical distribution system in his area of supply and to supply electricity in accordance with the provisions contained in this Act"*

- Section 61 (c) (Tariff Regulations)
  - *"the factors which would encourage competition, efficiency, economical use of resources, good performance and optimum investment"*

- Part – IX Central Electricity Authority, Section 73 (i) (Functions and duties of Authority)
  - *"collect and record the data concerning the generation, transmission, trading, distribution and utilisation of electricity and carry out studies relating to cost, efficiency, competitiveness, and such like matters"*

- Part X Regulatory Commission, Section 86(2) (Functions of State Commission):
  - *"State Commission shall advise the State Government on all or any of the following matters, namely:-*

    (i) promotion of competition, efficiency and economy in activities of the electricity industry;"

- Part – XVIII Miscellaneous, Section 166 (5) (Coordination Forum):
  - *"There shall be a committee in each district to be constituted by the Appropriate Government...*

    (c) to promote energy efficiency and its conservation"

As evident from the above provisions of EA 2003, the EA 2003 has clear provisions, which require key institutions such as the Electricity Regulatory Commission (ERC) and Utilities to promote efficient utilization of electricity. To ensure efficient utilization of electricity, it is necessary that the ERC/Utilities design and implement schemes that will promote the same. DSM is a methodology through which, Utilities can take initiatives to modify the consumption pattern on the consumer side of the meter.

In India, the State of Maharashtra has been at the forefront in undertaking DSM initiatives. It is suggested that the Commission not only continues the existing initiatives but also take new initiatives to ensure that energy efficiency and energy conservation is given the highest priority by the Utilities in the State.

8.2.3 National Electricity Policy

Section 86(4) of EA 2003 states that in discharge of its functioning, the Commission shall be guided by the National Electricity Policy (NEP) and the National Electricity Plan to be published by the Central Government and the Central Electricity Authority, respectively. The National Electricity Policy notified by the Government of India in 2005 has clear provisions for energy conservation and demand side measures. The relevant Clause of the Policy is reproduced below:

> ***"5.9 ENERGY CONSERVATION***
>
> *5.9.1 There is a significant potential of energy savings through energy efficiency and demand side management measures. In order to minimize the overall requirement, energy conservation and demand side management (DSM) is being accorded high priority. The Energy Conservation Act has been enacted and the Bureau of Energy Efficiency has been setup.*
>
> *5.9.2 The potential number of installations where demand side management and energy conservation measures are to be carried out is very large. Bureau of Energy Efficiency (BEE) shall initiate action in this regard. BEE would also make available the estimated conservation and DSM potential, its staged implementation along with cost estimates for consideration in the planning process for National Electricity Plan.*
>
> *5.9.3 Periodic energy audits have been made compulsory for power intensive industries under the Energy Conservation Act. Other industries may also be encouraged to adopt energy audits and energy conservation measures. Energy conservation measures shall be adopted in*

all Government buildings for which saving potential has been estimated to be about 30% energy. Solar water heating systems and solar passive architecture can contribute significantly to this effort.

5.9.4 In the field of energy conservation initial approach would be voluntary and self-regulating with emphasis on labelling of appliances. Gradually as awareness increases, a more regulatory approach of setting standards would be followed.

5.9.5 In the agriculture sector, the pump sets and the water delivery system engineered for high efficiency would be promoted. In the industrial sector, energy efficient technologies should be used and energy audits carried out to indicate scope for energy conservation measures. Motors and drive system are the major source of high consumption in Agricultural and Industrial Sector. These need to be addressed. Energy efficient lighting technologies should also be adopted in industries, commercial and domestic establishments.

5.9.6 In order to reduce the requirements for capacity additions, the difference between electrical power demand during peak periods and off-peak periods would have to be reduced. Suitable load management techniques should be adopted for this purpose. Differential tariff structure for peak and off peak supply and metering arrangements (Time of Day metering) should be conducive to load management objectives. Regulatory Commissions should ensure adherence to energy efficiency standards by utilities.

5.9.7 For effective implementation of energy conservation measures, role of Energy Service Companies would be enlarged. Steps would be taken to encourage and incentivise emergence of such companies.

5.9.8 A national campaign for bringing about awareness about energy conservation would be essential to achieve efficient consumption of electricity.

5.9.9. A National Action Plan has been developed. Progress on all the proposed measures will be monitored with reference to the specific plans of action."

8.2.4 Tariff Policy

The objective of the Tariff Policy (TP) is to promote competition, efficiency in operations and improvement in quality of supply, which accentuates one of the provisions in the EA 2003, which states that the tariff determination shall be guided by factors that encourage efficiency and economical use of resources.

8.2.5 Integrated Energy Policy Report (IEPR)

In August 2006, the Planning Commission of India released the Integrated Energy Policy Report (IEPR) of the Expert Committee. The IEPR targets sustainable development and covers all sources of energy and addresses all aspects of energy use and supply including energy security, access and availability, affordability and pricing, as well as efficiency and environmental concerns. Chapter VI of the IEPR, 'Policy for Energy Efficiency and Demand Side Management' not only restates the importance of EE and DSM and provisions already specified in the above-mentioned Policies, but also suggests the following policy initiatives:

1. Regulatory Commissions can allow utilities to factor EE/DSM expenditure into the tariff.
2. Each energy supply company/utility should set-up an EE/DSM cell. The BEE can facilitate this process by providing guidelines and necessary training inputs. A large number of pilot programmes that target the barriers involved and have low transaction costs need to be designed, tested with different institutional arrangements, with different incentives, and with varied implementation strategies. Innovative programme designs can then be rewarded.

Further, the IEPR has also suggested technology based initiatives and the process for implementing various DSM measures. While responsibility has been placed on BEE for some of these initiatives, the agencies for implementing other initiatives have not been identified.

8.2.6 National Action Plan for Climate Change (NAPCC)

The National Action Plan for Climate Change was announced by the Honourable Prime Minister of India on June 30, 2008, which gives significant importance to energy efficiency and implementation of DSM related programmes. One of the principles of NAPCC is to devise efficient and cost effective strategies for end-use Demand Side Management. One of the eight Missions of the Plan is the National Mission for Enhanced Energy Efficiency (NMEEE). The four pillars of the NMEEE are:

- Market based mechanism to enhance cost effectiveness of improvements in energy efficiency in energy-intensive industries through certification of energy saving that could be traded;

- Accelerating the shift to energy efficient appliances in designated sectors and to make the products more affordable;
- Creation of mechanisms that would help finance demand side management programmes;
- Development fiscal instrument to promote energy efficiency.

National Mission on Sustainable Habitat is another programme, which is being designed to ensure optimal usage of energy in the residential and commercial sector:

> *"Energy Conservation Building Code, which addresses the design of new and large commercial buildings to optimize their energy demand, will be extended in its application and incentives provided for retooling existing building stocks."(emphasis added)*

8.2.7 Summary of relevant Legal and Policy provisions

From the above, it is clear that the Commission is required to bring in principles of efficiency, economy and benign environmental policies into all activities being undertaken by it. Tariff determination, being the most important activity of the Commission, cannot ignore energy efficiency and DSM. While provisions of the EA 2003, EC Act 2001, NEP, TP, IEPR and NAPCC identify various EE and DSM activities that need to be undertaken, institutional structure is still evolving.

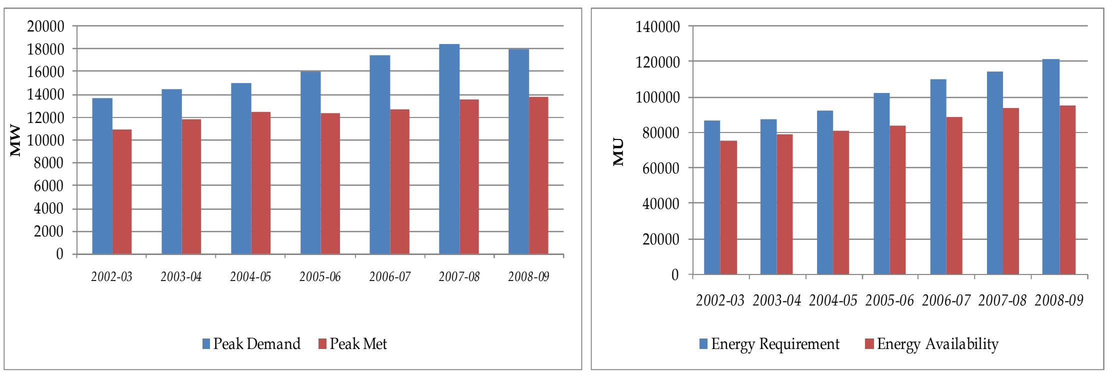
While Clause 5.9.2 of the National Electricity Policy has mandated BEE to initiate Action Plan to implement Demand Side Management and Energy Conservation measures, Clause 5.9.6 states that '*Regulatory Commissions should ensure adherence to energy efficiency standards by utilities*'. Given the fact that the DSM measures identified by the BEE will have to be implemented by the Utilities, which are under the jurisdiction of the ERCs, the ERCs will have to ensure that the Utilities undertake the programmes identified by BEE, with suitable modifications to take into account State and Utility specific conditions.

In the subsequent Sections of the Approach Paper, ABPS Infra has discussed various initiatives already undertaken to promote efficient utilization, proposed new initiatives and methodology to undertake DSM measures identified by BEE.

8.3 *Importance of DSM in the context of Maharashtra*

DSM brings about a reduction in electricity demand and electricity demand growth rates. The State of Maharashtra has witnessed rapid economic growth and is not in a position to meet its requirement, either in energy terms or peak capacity terms. Energy requirement of the State has increased from 87152 MU in FY 2002-03 to 121890 MU in FY 2008-09. In FY 2002-03, the energy shortfall was 11680 MU, which increased to 26140 MU in FY 2008-09. Peak demand in Maharashtra has increased from 13697 MW in FY 2002-03 to 18049 MW during FY 2008-09; however, the State was able to meet demand of only 13767 MW in FY 2008-09. The following Graphs show demand supply scenario (in terms of demand and energy) for the last seven years.

Figure: Power Supply Position in Maharashtra



Source: Central Electricity Authority

Considering the huge demand supply mismatch prevalent in the State of Maharashtra, the need and importance of DSM is evident. A study carried out by Shri. Jayant Sathaye of Lawrence Berkeley National Laboratory (LBNL) and International Institute for Energy Conservation (IIEC) under the United State Agency for International Development (USAID) funding in FY 2004-05 estimated the DSM potential to be of the order of about 1300 MW. As per preliminary estimates, the present DSM/EE potential is estimated to be in the range of 2000-2300 MW and 400-450 MW for the State of Maharashtra (MSEDCL license area) and Mumbai city, respectively.

Despite huge potential and several efforts initiated by the Commission, the savings achieved through the implementation of various demand side management measures in the State over the past three/four years are in the range of 15 to 20 MW only. Because of its huge untapped potential for reduction of electricity demand, the Commission has identified DSM as a critical and a strategic element for mitigating power shortage in the

State of Maharashtra. Given that the significant demand supply gap is likely to continue in the near and medium-term, power shortage mitigation will have to remain one of the key DSM policy objectives of the Commission.

8.4 Purpose and Scope of DSM

The purpose of DSM activities, or DSM programmes as they are popularly termed, is conservation or efficient utilisation of electricity, i.e., reduction in electricity consumption (kilowatt hours or kWh), or load management, i.e., the reduction in power demanded (kilowatts or kW or KVA) or the displacement of demand to off-peak times or a combination of both – reduction of electricity consumption and reduction in power demand. According to the purpose, DSM programmes have come to be classified into four broad types:

a. Peak Clipping Programmes

The basic purpose of these DSM programmes is to reduce consumer demand during system peak times. Such programmes, apart from reducing electricity demand, also usually lead to reduction in electricity consumption. These programmes not only provide opportunities for avoiding, reducing or postponing the need for installation of new generation, transmission and/or distribution capacity, but also provide opportunities for reducing the need for the distribution Utilities to purchase costly power to meet peak demand. In the Maharashtra context, such programmes can help the distribution Utilities in balancing their supply-demand equation.

For example, Utility programmes promoting use of compact fluorescent lamps or T-5 or high lumen T-8 fluorescent tube lights (FTLs), or use of efficient ballasts for FTLs, are all examples of peak clipping programmes as they reduce the lighting load during evening time when Utilities such as MSEDCL/RInfra-D experience their peak.

b. Load Shifting Programmes

Such programmes lead to reduction in electricity demand (kW or kVA terms) during peak period but do not necessarily lead to reduction in electricity consumption (kWh terms) as the entire consumption, as before, now takes place during non-peak periods. Like 'peak clipping' programmes, these programmes too provide opportunities for avoiding, reducing or postponing the need for installation of new generation, transmission and/or distribution capacity. They also help the Utilities to avoid the purchase of costly power to meet peak demand as well as provide options for distribution Utilities to balance their demand-supply equation.

For example, operation of municipal water supply or sewage disposal pumps during night/early morning hours, chilling and storing the chilled water required in central air-conditioning plants during early morning/night hours are examples of 'load shifting' programmes. Time of day metering is a tool that is often used to promote these types of DSM programmes.

c. Strategic Conservation Programmes

Such programmes lead to reduction in electricity consumption (kWh) and also lead to reduction in consumer demand (kW or KVA) as a spin-off, though such reduction in demand may or may not occur during peak periods. These programmes, while providing reduced electricity consumption or saving in electricity use, may not necessarily provide opportunities for avoiding, reducing or postponing the need for creation of new generation and/or network capacity. In the Maharashtra context, however, such programmes help the distribution utilities in reducing their 'energy' shortages.

For example, Utility programmes that promote conservation of electricity or its efficient utilization in end-use appliances, equipments or processes are all examples of strategic conservation programmes.

d. Valley Filling Programmes

The basic purpose of Valley Filling Programmes is to increase electricity load and consumption during off-peak hours. Such programmes lead to higher electricity consumption but also lead to better and enhanced utilization of the existing generation, transmission and distribution capacity and thus, results in reduced overall cost of electricity.

Considering the significant demand supply gap and untapped energy efficiency and demand side management potential existing in the State of Maharashtra, the Commission has taken several initiatives as discussed in the subsequent paragraphs.

8.5 Existing Initiatives of the MERC

For an industry whose operations are mandated by the conditions of the licence and whose operations on the cost and revenue side are regulated, it is imperative that activities such as DSM, which have cost and revenue implications, are mandated by Regulations. Section 61 of EA 2003 mandates Electricity Regulatory Commissions to regulate electricity tariffs and specifies that the guiding factors to be considered while setting tariffs should include "*the factors which would encourage competition, efficiency, economical use of resources, good performance and optimum investments*". Considering the large demand supply gap and ample scope for reducing costs, the Commission has taken recourse to the power vested in ERCs under Section 23 of the EA 2003 to direct Utilities in Maharashtra to undertake DSM activities.

The Commission has been very proactive and has expressed its commitment to the cause of energy efficiency, energy conservation and demand side management by undertaking following initiatives:

- EE and DSM in MERC Tariff Regulations;
- Tariff Related Initiatives:
    - Time of Day Tariffs;
    - Power Factor Incentives and Penalty;
    - Load Management Charges;
- Other Regulatory Directives/Initiatives related to EE and DSM;
- Preparation of EE and DSM Guidelines;
- Development of methodology for financing of DSM & EE Initiatives of Utilities

Each of the abovementioned initiatives has been discussed in the following paragraphs.

8.5.1 EE and DSM in MERC Tariff Regulations

Considering the available potential for demand side options, the Commission, in its MERC Tariff Regulations, has treated Energy Conservation (EC) and Energy Efficiency (EE) measures as supply side resources and specified that distribution licensees should consider EE and EC measures while formulating the long-term power procurement plan.

The relevant extract of Regulation 23.2 (d) in this respect is as under:

"23.2 The long term power procurement plan by Distribution Licensee shall comprise the following:

………..

(d) Measures proposed to be implemented as regards energy conservation and energy efficiency."

Accordingly, the Commission has issued several directives to the distribution Utilities in the State through its various Tariff Orders issued from time to time.

8.5.2 Tariff Related Directives

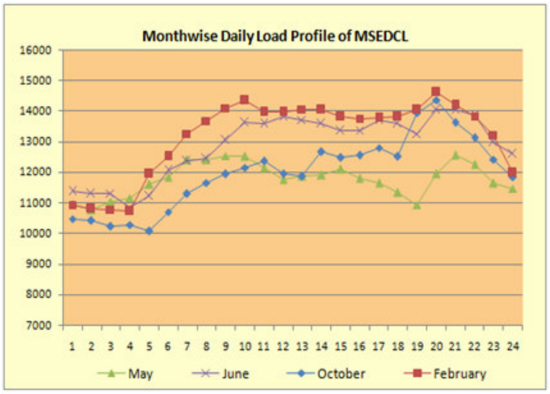
Since, tariff determination is a core function of the State Electricity Regulatory Commission (SERC) under Sections 61 to 64 and 86 of the EA 2003; SERCs can play a critical role in promoting demand side management by way of appropriate tariff structures. The Commission has issued several tariff related directives to encourage consumers to reduce their demand during certain periods. Some of the tariff related directives issued by the Commission are discussed below:

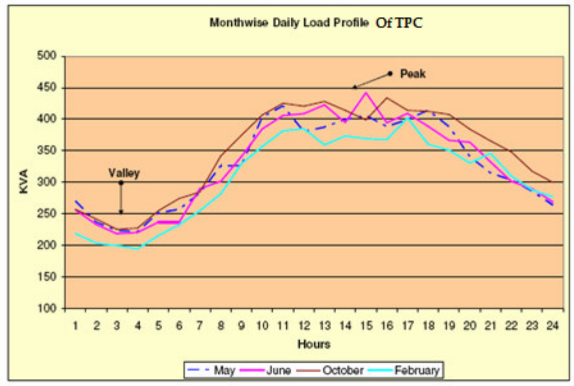
8.5.2.1 Time of Day Tariff

As a DSM measure, 'Time of Day' initiatives aim to change customers' energy-using behaviour, particularly to alter the periods during which electricity is used. Time of Day Tariff is typically used to reduce the demand on the system during peak period.

Typically, the system demand during different hours of the day varies significantly. The demand during peak hours is usually much higher than the demand during off-peak hours. Under such circumstances, the distribution Utility and the Generation Company are required to build the distribution infrastructure and generation capacity, respectively, to cater to the demand during the peak hours. If infrastructure is designed to meet highest demand, it would result in lower capacity utilisation factor as the highest demand exists for only few hours in a year. If the infrastructure is designed for lower demand, there exists a possibility of it not being able to serve the maximum demand. Also, the infrastructure could get overloaded, which could result in higher losses as well as higher probability of failure.

Ideally, the Utilities would prefer to have a flat load curve throughout the day, as this would reduce the capital investment required, and would also ensure very high capacity utilisation factors. However, this is not practical as the Utility has rarely got any control over the consumption by the consumers. Further, the consumption pattern of different consumer categories varies significantly. Different categories impose different loads on the system during different hours of the day. This is obvious from the daily load profile of two distribution utilities (MSEDCL and TPC-D) for the months of May, June, October and February, which is presented below:





Based on the analysis of TPC load profile, it can be observed that peak demand occurs during 0900 to 1700 hours however, sharp plunge in the demand occurs during 0100 to 0500 hours. The primary reason for occurrence of peak demand during 0900 and 1700 hours is higher share of industrial and commercial sector in TPC's overall consumer mix.

The load profile of MSEDCL shows occurrence of morning and evening peaks at around 0800 to 0900 hours and 2000 to 2100 hours respectively. MSEDCL load profile further indicates that load varies significantly in different months as compared to TPC load profile, which could be due to variation in climatic conditions and significant variation in consumer profile. Mumbai experiences almost similar climatic conditions throughout the year while MSEDCL, catering to large area, has varied climatic conditions in different divisions of its area of supply. Based on the analysis of load pattern of MSEDCL and TPC, it can also be seen that the difference between peak demand and off-peak demand is also quite significant due to variation in consumer mix and electricity usage pattern.

As discussed earlier, ideally the distribution Utilities would prefer to have a flat load curve during the entire day, which is not possible in real life as the load pattern of different consumers varies significantly during the day. However, it is possible to reduce the differential between the demand that exists during peak hours and that during off-peak hours through tariff mechanisms such as 'time of day' charges. Under this approach, different energy charges are levied on energy consumption during different hours of the day, which incentivises users to shift their demand from peak period to the off-peak period. This is a tried and tested approach to flatten the load curve. However, it has to be borne in mind that it may be quite possible that demand of some of the consumer categories contributing to the peak demand is inelastic and cannot be shifted to off-peak hours; in such case the ToD tariffs will have to be levied on the consumer categories such as industrial consumers, who can actually shift their consumption to off-peak hours. However, for designing the ToD tariffs, it would be required to have an idea of the system load curve, as well as the category-wise load curves. Further, it is necessary to bear in mind the availability of supply-side resources to meet peak demand. If significant peaking resources are available, it may not be necessary to have ToD tariffs. The extent of tariff differential between peak and off-peak hours also need to be deliberated upon. Maharashtra has been a pioneer in implementation of 'Time of Day' tariffs in the country.

The Commission introduced time of day tariff for HT-I (Industrial – BMR/PMR) and HT–II (Industrial-others) consumer categories of MSEDCL through its Tariff Order dated April 28, 2000 (detailed Order dated May 5, 2000). For 'Time of Day' charges, one day, i.e., twenty-four hours has been divided into five tariff periods. The normal tariff period is between 0600 and 0900 hours and 1200 and 1800 hours, i.e., for 9 hours comprising 37.5% of the total time of the day. The peak period was defined from 0900 hours to 1200 hours and evening 1800 hours to 2200 hours, i.e., for 7 hours comprising 29.1% of the total time of the day. The off-peak period was defined between 2200 hours and 0600 hours in the morning, i.e., for eight hours, which constitutes 33.33% of the total time of the day. In this Tariff Order, the Commission levied additional energy charges of 30 paisa/unit and 60 paisa/unit during morning and evening peak hours, respectively. The Commission also introduced rebate of 50 paisa/unit on base tariff for energy consumed during the off-peak hours.

In its Tariff Order dated January 10, 2002, the Commission increased the additional energy charges to 50 paisa/unit and 90 paisa/unit for morning and evening peak period, respectively. The Commission also provided additional rebate of 25 paisa/unit (total 75 paisa/unit) on base tariff during off-peak hour period for HTP-I and HTP-II categories. In this Tariff Order, the Commission also extended applicability of ToD tariff to two more HTP categories, i.e., HTP-III and HTP-IV. The Order also offered an option of ToD tariff to LTP-G category. However, for these new categories, the Commission maintained the rates as determined vide its Tariff Order dated April 28, 2000.

The Commission has modified the rates in its subsequent Tariff Orders dated March 10, 2004, October 20, 2006, May 18, 2007 and June 20, 2008. The Commission has also increased the consumer categories to which ToD tariffs are applicable. Currently ToD tariffs are applicable to most LT categories and HT categories where MD metering facility exists.

The Commission has adopted the same time slots for time of day tariffs for all Utilities in the State, though load curves of different Utilities are significantly different. The Commission has strived to optimize the load curve for the State as a whole and not for every individual Utility. Hence, for designing an effective ToD tariff, it would be required to have an idea of the system load curve and the category wise load curves. For development of category wise load curves, it is essential that distribution Utilities make load research an integral part of their day to day operations.

Therefore, it is proposed that in the next Control Period, the MERC MYT Regulations shall require all Utilities to undertake extensive load research to understand contribution of each category to the load curve. Based on this research, all distribution Utilities shall submit the proposals for 'time of day' tariffs. The Utilities shall submit to the Commission, data related to seasonal variations as well as the load profile during weekend/weekdays while designing the time of day tariff. Based on the information submitted, the Commission may consider redefining both time slots as well as quantum of charges for 'ToD' tariff during the next Control Period.

8.5.2.2 Power Factor Incentive and Penalty /Reactive Power Charges

Power factor in alternating current circuits is the ratio of energy consumed (watts) versus the apparent power (volts-amp). Power factor correction aims to reduce the difference between the energy consumed and the apparent power so as to reduce energy wastage. Most power factor correction projects reduce overall demand across the whole electrical load curve. It may also be possible to use power factor correction to reduce demand at the time of the system peak if loads that contribute to that peak can be identified and power factor correction applied specifically to those loads. Power factor correction can be deployed strategically in geographical areas where network constraints occur or can be implemented in particular localities to reduce demand on a specific network element.

Different methodologies such as Power Factor Incentive and Penalty or Reactive Power Charges can be adopted for maintaining the power factor within the desired limit. While this mechanism could be applied to a large variety of consumers, it is generally applied to only industrial category consumers, who install automatic power factor correction controllers to maintain close to unity power factor.

With a view that the distribution Utility in the State of Maharashtra (erstwhile MSEB) maintains power factor within the desired limit, the Commission introduced power factor incentive for HT-I (Industrial – BMR/PMR) and HT – II (Industrial-others) consumer categories of MSEB through its Tariff Order issued on April 28, 2000. Power factor incentive at the rate of 1% (one percent) of the amount of the monthly energy bill was introduced for maintaining the power factor greater than 0.95. However, MERC did not impose any penalty for failure to meet the power factor within the desired limit.

In the Tariff Order issued on January 10, 2002, the Commission introduced additional power factor incentives of 2% (total 7%) for maintaining unity power factor. In this Tariff Order, MERC also introduced a penalty of 1% of monthly energy bill for fall in the power factor below 0.9. The Commission also extended applicability of power factor incentives and penalty for LTP – G- General Motive Power and to all HT categories except Railways.

With view that HT & LTP – G consumer categories take steps to maintain the power factor within the desired limit, the Commission, in its Tariff Order dated March 10, 2004, levied a penalty of additional 1% (total 2%) of monthly energy bill for maintain the power factor 0.9>PF>0.89 and 1% for each percentage point fall in the power factor below 0.89. MERC did not make any additions to the consumer categories with respect to the applicability of the power factor incentives and penalties in this as well as the Tariff Order issued on October 20, 2006.

However, in the Tariff Order issued on May 18, 2007 for MSEDCL, the Commission included three LT categories, viz. LT-III (PWW), LT-IV (Industrial) and LT-IX (Multiplex & Shopping Malls above 20 kW) for levying power factor incentives and penalties. The Commission did not change the incentives and penalty charges.
Apart from MSEDCL, MERC had also specified a penalty of 2% of monthly energy bills and demand charges for fall in power factor below 0.91 for RInfra and TPC through its tariff order dated June 2004 for all HT categories except Railways and LTP- General

Motive categories. Further, present rates (power factor incentives/penalties) are similar to those applied in case of MSEDCL.

8.5.2.3 Load Management Charges

Under Section 61 of the EA 2003, the Appropriate Commissions are required to determine tariff in a manner that will encourage efficiency and economical use of resources. These provisions provide significant flexibility to Regulators in developing tariffs appropriate for promotion of EE and DSM. In this regard, the Commission issued directives to the MSEDCL to restrict consumption by the continuous process industries to 90% and non-continuous process industries to 80% of their average monthly consumption during the previous one year. For all the Distribution Licensees, the Commission also levied Load Management Charges on the consumers who did not restrict their consumption within the stipulated limit, and prescribed Load Management Rebate for consumers who restricted their consumption to below the stipulated limit. MERC also directed the distribution Utilities to use the net amount collected as Load Management Charge for promotion and implementation of energy efficiency, energy conservation and demand side management measures. The relevant extract of MERC Tariff Order for TPC-D of FY 2005-06 and 2006-07 in this respect is as under:

> *"The money collected through the levy of this "Load Management Charge" has to be maintained in a separate fund to be used for energy conservation and Demand Side Management (DSM) measures".*

In response to the Review Petition filed by industries and consumers associations, MERC withdrew Load Management Charge Order in December 2006.

8.5.3 Other Directives/Initiatives related to EE & DSM

In order to capture the DSM potential, distribution Utilities will have to pursue all DSM options; not only in those sectors where cost of supply is higher than prevalent tariffs but also in those sectors where cost of supply is lower than the prevalent tariffs. In order to encourage the distribution Utilities in the State to take up non-tariff DSM measures, the Commission had also taken several initiatives as described below:

- The Commission has directed all Utilities in the State to develop the necessary infrastructure for implementation, monitoring and verification of DSM programmes. The Commission has also suggested that all distribution Utilities in the State of Maharashtra should create a dedicated DSM Cell to carry out various activities associated with DSM.

- The Commission, in its Order dated March 4, 2005, directed MSEDCL to submit a DSM Plan for capturing energy conservation and energy efficiency potential in various electricity consuming sectors in Maharashtra to ward off load shedding that was being resorted to by MSEDCL to balance its demand supply situation. Subsequently, when the prospect of a prolonged phase of load shedding began to loom large over Mumbai city also, which hitherto had not witnessed load shedding, the Commission directed the distribution Utilities (BEST, REL and TPC) supplying power in Mumbai city to prepare DSM plans and undertake DSM/EE programmes. While Utilities in Mumbai have established DSM Cells, the largest Utility in Maharashtra, i.e., MSEDCL has not taken significant efforts in this regard.
- As mentioned earlier, the Commission, in its MERC Tariff Regulations 2005, has treated EC and EE and measures as supply side resources and specified that distribution licensees should consider EE and EC measures while formulating their long-term power procurement plan. The overall cost of power procurement could have been lower if the distribution Utilities had integrated demand side options with supply side options. In order to ensure that consumers need not have to pay for higher overall cost of power procurement because of ignorance of demand side options, the Commission through its Multi Year Tariff (MYT) Orders of April/May 2007, directed the distribution Utilities in Mumbai city to reduce 2% of costly power purchase through DSM measures. Since the consumers in MSEDCL licence area were already suffering from severe load shedding, such a directive was not given in case of MSEDCL. Te relevant text from the MYT Order is reproduced below:

Multi Year Tariff Order for the Control Period FY 2007-08 to FY 2009-10
(Para 5.4, DSM Mechanism for TPC-D)
"…In the absence of detailed data and analysis, however, the Commission, at this juncture, is not in a position to arrive at the exact quantum by which power procurement cost would have been lower. Nevertheless, the Commission, being in, "in principle" agreement with the observation that consumers are having to pay higher overall cost of power procurement because the distribution licensees have ignored demand side options, and that too despite Commission's Tariff Regulations explicitly providing for

consideration of such options; the Commission has assumed that 2% of the costly power purchase requirement will be reduced through DSM measures…"

- Distribution Utilities in the State have virtually no category-wise demand and consumption data beyond the system level demand (no data on contribution of sector or segment or end-use or technology to the total demand and consumption, both, in terms of quantum or timing). In the absence of such data, the Utilities in the State are not able to strategise and plan EE and DSM programmes. Consequently, the EE and DSM initiatives undertaken so far by the Utilities in the State have been ad-hoc, and at best have been in the nature of demonstration or pilot projects. Recognising the absence of planning data as a major constraint for speedy development and implementation of full-fledged EE and DSM programmes, the Commission through its Multi Year Tariff (MYT) Orders of April/May 2007, directed all the distribution Utilities in the State to undertake systematic load research and to make load research an integral part of their the day-to-day operations. The relevant text from the MYT Order is reproduced below:

Multi Year Tariff Order for the Control Period FY 07-08 to FY 09-10
(Para 5.4, DSM Mechanism for TPC-D)

"…In order to assess the impact of DSM initiatives on the overall demand for electricity and on the overall costs to be incurred to meet a particular level of consumer demand, ***it is essential to continuously track and monitor the extent to which load and consumption are getting affected due to DSM initiatives.*** *Systematic load research is a key to providing this data. Load research, apart from providing data on DSM benefits, would also provide insight about consumer load profile (who are the consumers, how much are they consuming, purpose of consumption, where they are consuming and at what time they are consuming), data on cost of service, data on profitability analysis, and also help the distribution licensee in rate design, load forecasting, load control and load management.* ***The Commission therefore, directs the distribution licensees to initiate systematic load research exercise on a continuous basis and to make load research an integral part of their operations....***" (***emphasis added***)

- Recognising that the distribution Utilities, who are regulated entities, would need regulatory approval to recover costs associated with EE/DSM programmes, the Commission has allowed distribution Utilities in the State to recover all costs incurred any DSM and/or EE related activities, including planning, designing, implementing, monitoring and evaluation through their aggregate revenue requirement. Relevant text from the MYT Order for the Control Period from FY 2007-08 to FY 2009-10 is reproduced below:

> *".....As has been repeatedly proclaimed by the Commission,* ***the Commission is committed to allow as pass through in the ARR, all the cost incurred by the distribution licensees on design, development and implementation of DSM initiatives....".(emphasis added)***

8.5.4 Preparation of EE & DSM Guidelines for Utilities

While the concept of DSM is not new, very little implementation experience is available in the country. As a result, significant uncertainty regarding issues related to design, development and implementation of DSM programmes exist in the country. There is no specific criteria, which will guide Utilities in designing programmes or will assist the Regulators in assessing effectiveness of the programmes. In order to overcome these barriers, the Commission has prepared Cost Effectiveness Assessment Guidelines for assessing DSM programmes from the point of view of participants, Utility and society. The Commission has also prepared a Discussion Paper on "Regulatory Framework for Demand Side Management". Important aspects of both are discussed in the following paragraphs.

8.5.4.1 Draft Cost Effectiveness Assessment Guidelines, January 2009

Any DSM programme should be taken up only after ascertaining feasibility and sustainability through cost-benefit analysis of such programmes from Utility as well as consumer perspective. Under the cost-benefit analysis, the likely benefits from the proposed programmes to the distribution Utility as well as participant should be quantified in energy (kWh) and demand (kW) terms. These benefits should be subsequently valued in monetary terms. If the perceived benefits of a proposed DSM project are likely to exceed the potential costs of the project, then only that DSM project shall be approved by the Commission. On the other hand, if the project's costs are perceived to be greater than potential benefits, then the project should not be taken up by the Utility.

In this regard, the draft 'Cost Effectiveness Assessment Guidelines' issued by the Commission in January 2009 provide guidance to the distribution licensees for assessing the cost effectiveness of the DSM programmes and thus, reduce the uncertainty faced by them in regulatory approval. Further, these guidelines will reduce the regulatory burden while scrutinising DSM proposals of the distribution licensees.

8.5.4.2 Discussion Paper on Regulatory Framework for DSM, June 2009

Though the Commission has taken several initiatives for development and implementation of DSM measures, these have remained pilot in nature. For large scale deployment of EE & DSM programmes, a comprehensive regulatory framework for DSM is needed. This regulatory framework should guide all stakeholders on issues such as eligibility and selection criteria, roles and responsibilities of various stakeholders, funding arrangement, DSM targets and budgets, process and procedures for submission, appraisal, approval, monitoring, evaluation and reporting, etc.

The draft Discussion Paper published by the Commission on Regulatory Framework for DSM, covers the following issues:

- Possible Policy objectives of MERC vis-à-vis DSM
- Possible guiding principles of MERC for the DSM efforts in the State
- Eligibility criteria – what kind of DSM programmes could be allowed by MERC and which DSM programmes will not be allowed by MERC
- How the DSM effort should be organised under multi-year tariff regime?
- What could be the institutional structure for management of DSM effort in the State?
- How should the DSM targets and funding levels be decided and what could be the targets and funding levels?
- What should be the procedure for approval of DSM plans/programmes?
- What should be the criteria for deciding which DSM programmes should form part of five year DSM plan?
- Evaluation, measurement and verification
- Monitoring and reporting
- Post Programme reporting
- Possible contents of a DSM Plan Document
- Possible Contents of a DSM Programme Document

It is envisaged that the regulatory framework proposed above, once finalised, would provide a consistent set of methods and procedures for DSM plan/programme design, preparation, period, load research, consumer surveys and benefit cost assessment, etc. In this regard, it is proposed that in the next Control Period, the Commission shall prepare Maharashtra specific DSM Regulations in accordance with the Discussion Paper mentioned above. It is also proposed that the Commission shall prepare various specific guidelines such as guidelines for monitoring and verification of DSM programmes, etc.

8.5.5 Financing of EE and DSM Initiatives of Utilities

As discussed earlier, the savings achieved through the implementation of various pilot scales DSM measures in the State over the past three/four years are in the range of 15 to 20 MW only. Barriers related to untested outcomes, lack of clarity about baseline data and Measurement and Verification (M&V) protocol and non-availability of financing options are some of the major reasons for distribution Utilities not taking up large scale DSM projects. While clarity on regulatory issues is being provided through the Discussion Papers mentioned above, it is also necessary that necessary financing avenues are made available to the participants in the programmes.

The Commission has been very proactive in the field of EE and DSM and has adopted the following two mechanisms to ensure availability of funds for the design, development and implementation of DSM programmes.

- Development of Special Fund
- Recovery of Cost through Aggregate Revenue Requirement

8.5.5.1 Development of Special Fund

Sometimes, it may be possible to create Special Funds either within the Utility or outside the Utility, which may be used by the Utilities for design, development and implementation of DSM programmes. An example of fund created outside the Utility is Urjankur Nidhi created by the Government of Maharashtra. The Fund is formed from the money collected by way of levy of cess of 4 paisa on all units sold to commercial and industrial category consumers in the State of Maharashtra.

Under special circumstances, the regulatory framework could be used for creation of special Funds. Such framework could involve levy or surcharge on existing consumption or incremental consumption or incremental demand, depending on the purpose of the Fund.

One such example of development of Special Fund is ‘Load Management Charge’ Fund created by various Utilities in the State of Maharashtra based on the directives given by the Commission. In May 2005, under Section 23 of the Electricity Act, 2003, the Commission directed all consumers to reduce their consumption to certain level. A surcharge of Rs. 1/kWh was levied on consumption above norm specified by the Commission, and a rebate of Rs. 0.50 per kWh was provided for reduction in consumption below the norm set by the Commission. The Commission directed that the amount so collected by Utilities shall be used for promotion of energy efficiency, energy conservation and demand side management. The distribution Utilities in the State collected around Rs. 70 Crore during the two month period from May to June 2005. Till date, this amount is being utilised to execute EE/EC/DSM programmes in the State. It is important to note that though approval of costs by the Regulators will be required even in this case, the costs are neither borne by the distribution Utilities nor passed on to the consumers.

8.5.5.2 Recovery of Cost through Aggregate Revenue Requirement

Direct costs associated with programme administration including design, implementation, monitoring, evaluation and incentives, if not recovered, could impact earnings of the Utility. Reasonable certainty of cost recovery is a necessary condition for Utility programme spending, as failure to recover any costs directly impacts the Utility's earnings, and sends a discouraging message regarding further investment. Regulatory interventions to include DSM related expenditures as a part of the Aggregate Revenue Requirement (ARR) in order to recover the same through tariffs is needed.

In case of approval of expenses under the ARR, the Utility is certain about recovery of the costs through consumer tariffs. In this case, the Utility funds capital expenditure using same financing principle as used for other capital projects of the Utility. The Commission allowed distribution Utilities to specifically recover all costs incurred by them on DSM and/or EE related activities, including planning, designing, implementing, monitoring and evaluating DSM and/or EE/EC programmes through their ARR. However, since the costs related to DSM are being paid by the consumers through tariffs, the Commission has given emphasis on those DSM projects whose cost effectiveness is established as per the guidelines developed by the Commission.

Hence, following provisions will have to be made in the MERC MYT Regulations to allow recovery of DSM related expenditure as a part of ARR in order to create necessary funding mechanism for the implementation of DSM programmes:

- Recognition of expenditure incurred on DSM activities as either revenue expenditure or capital expenditure;

- Recovery mechanism for expenses incurred for the implementation of DSM schemes; e.g. specifying depreciation rates for capital expenditure related DSM initiatives
- Designing suitable means for financing of DSM activities (ESCO, Fund Creation, etc);

8.5.6 Development & Implementation of DSM Bidding Process

DSM Resource Acquisition is a mechanism to implement DSM projects through customers, Energy Service Companies (ESCOs), Non Governmental Organisations (NGOs), equipment manufacturers/suppliers, or other private sector organizations, with payment made to them by the Utility for the resultant energy and load reduction. The DSM Resource Acquisition approach may be very useful for quickly achieving peak load reduction and may therefore, represent an excellent option for States that are experiencing severe capacity shortages. Further, the competitive bidding approach offers the advantage that it may cost less to acquire the resources using this approach because of market competition.

As discussed earlier, Maharashtra State is facing severe power shortage in terms of energy and peak capacity requirement. With this background, the Commission initiated a study to assess the feasibility of DSM Resource Acquisition scheme to get substantive benefits to the distribution system challenges in Maharashtra. Under the study, the Consultant had to propose the DSM bidding process that would take into account benefits from several end uses such as lighting, water pumping and water heating in the domestic sector. Under this approach, analysis of the identified feeders was carried out. Based on the analysis, implementation options have been developed. On the development of implementation options, DSM Resources will be made available to interested parties for management and implementation of DSM measures.

Currently, competitive bidding is in progress for selection of the bidder for two feeders in the area of Reliance Infrastructure Limited. However, it is noted that this bidding has not drawn favourable response from ESCOs. One of the reasons is lack of capability among ESCOs. Other possible reasons for lack of response are the non-availability of suitable financing mechanisms and lack of clarity on M&V protocol. In order to promote large scale implementation of energy conservation and energy efficiency measures through the ESCO route, BEE has now empanelled over thirty ESCOs through an accreditation process. This accreditation exercise has helped provide the technical and financial due diligence that is necessary to create a sense of credibility amongst the prospective distribution Utilities who are likely to secure the services of ESCOs as well as amongst the financial institutions who would be expected to provide the debt and working capital to the ESCOs.

Hence, it is proposed that in the next Control Period, the Commission while framing the DSM Regulations should promote the competitive bidding approach for the implementation of the various DSM measures identified by the distribution Utilities. It is also proposed that the Commission should prepare guidelines for the monitoring and verification of DSM programmes, which will help ESCOs as well as Financial Institutions for taking up DSM programmes through this innovative route. It is also proposed that the Commission should encourage distribution Utilities (mainly private) to create their own ESCO as an unregulated activity in order to capture the business opportunities by implementation of DSM and EE projects in their licenced areas.

8.6 Proposed DSM Initiatives

All entities in the State must promote energy efficiency and conservation measures, and develop and implement appropriate DSM measures. The proposed DSM initiatives that may be taken up by the Commission during the second Control Period have been discussed in the subsequent paragraphs.

8.6.1 Inclusion of EE/DSM in planning process

Consumption patterns of different consumer categories are quite different. In order to undertake effective DSM programmes, strong database of consumer profile as well as an idea of the system load curve and the category-wise load curve is required. Hence, it is necessary to undertake load research programmes on continuous basis to ascertain the pattern of consumption by consumers in the area of the Utility.

It is necessary that the total potential for EE/DSM in the State is identified. This assessment will have to be undertaken by an entity other than the Utilities. It is understood that BEE is undertaking this activity on behalf of the State Designated Agencies in some of the States. It is proposed that the Maharashtra Energy Development Agency (MEDA), the State Designated Agency in the State of Maharashtra, undertakes this activity either on its own or with the assistance of BEE. The Commission can use this estimated potential for EE/DSM in the State to set targets for various Utilities for their individual DSM programmes. These targets will be incorporated by the Utilities in their power procurement policies.

8.6.2 Rebate / Incentives for Solar Water Heating Systems

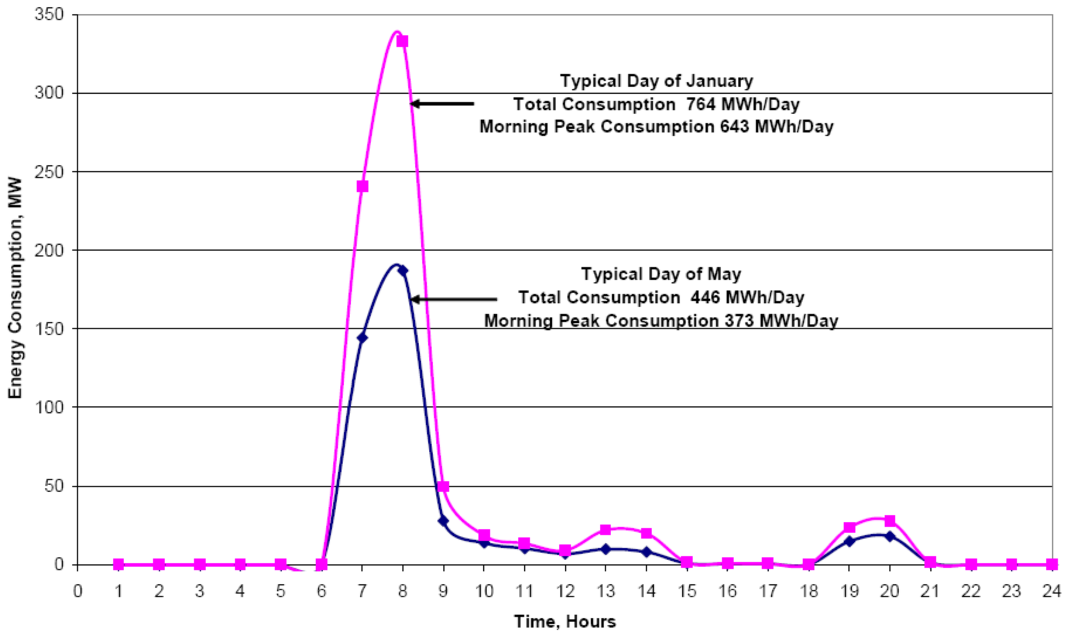
As a DSM measure, energy efficiency and fuel switching leads to reduced load levels on the electricity network. While fuel substitution results in electricity loads being lost to other fuels, probably permanently, in case of energy efficiency, the end uses continue to be served by electricity albeit at a reduced level.

The load curve of Maharashtra system shows distinct morning and evening peaks. One of the primary reasons for morning peak is usage of water heating appliances such as electrical geysers, heating coils, etc. In this regard, a study[1] had been carried out by Indian Institute of Technology, Mumbai in March 2007, which has estimated technical potential for solar water heating system (SWHS) for Maharashtra and few of its major cities along with estimation of annual electricity savings. Technical potential for the State of Maharashtra is presented below:

	Selected District/State	Population (million)	% Urban population	Estimated potential	
				Electricity savings (GWh)	Collector Area (million sq. m.)
1	Maharashtra	96.9	42.4	1620	7.60
2	Mumbai	1.20	100	477	2.47
3	Pune	7.22	58.07	242	1.00
4	Nagpur	4.05	64.36	129	0.62

The study also included detailed load research and developed load profiles of energy requirement for water heating on a typical day of winter and summer for the city of Pune. The pattern of energy requirement for water heating systems in the city of Pune is presented below:

[1] Draft Paper on An Analysis of Maharashtra's Power Situation by Prof. Rangan Banerjee of IIT, Bombay, March 2007



The Figure presented above clearly shows that usage of energy for water heating is maximum during the morning peak hours (out of total energy consumption on water heating requirement, 83 to 84% of energy is used during the morning peak hours between 0600 to 1000 hrs). Thus, utilization of solar water heating systems will definitely contribute to reduction of morning peak demand.

A typical solar water heating system can save up to 1500 units of electricity every year for every 100 litres per day of solar water heating capacity. Various mechanisms such as fiscal incentives by the Government, rebate in property tax and rebate in electricity bills have been deployed to promote SWHS in the country. However, it is important to note that distribution Utilities have direct incentives in promotion of SWHS as these reduce the requirement of the generation capacity in the grid as well as reduce costly power procurement during morning peak hours. This will help distribution Utilities in meeting their Universal Service Obligation, which is not being met currently by MSEDCL. While Mumbai based utilities are able to meet electricity to their consumers, these utilities will benefit by implementing SWHS as the cost of power purchase will come down. A few SERCs have already provided rebates for SWH systems. The following table provides details of the rebates being provided by the Utilities upon approval by the respective SERC.

State	Rebate
Assam	Rs. 40 / month
Rajasthan	Rs 0.15 per kWh
Haryana	Rs. 100 / 100 lpd, Rs. 200 / 200 lpd, 300 / 300 lpd
Karnataka	Rs 0.50 per kWh to a max. of Rs. 50/ month
Uttarakhand	Rs. 75 /month for 100 lpd installation
West Bengal	Rs 0.40 per kWh to max. of Rs. 80

According to the study carried out by IIT Mumbai, potential of 7.6 million sq. m collector area exists in the domestic sector in Maharashtra. According to MNRE estimates, significant potential exists in Maharashtra for solar water heating applications. Considering this huge untapped potential in the State of Maharashtra and its effectiveness in reduction of morning peak demand, it is proposed that the Utilities should carry out detailed study to assess the benefits through installations of SWH systems in their area of supply. Based on their assessment, Utilities should submit suitable mechanisms including commercial incentives for the promotion of SWHS for the residential and commercial consumer categories.

8.6.3 Rebate / Incentives for ECBC Compliant Buildings

There is a huge potential of energy savings in existing buildings. Energy Audit studies conducted in several office buildings, hotels and hospitals indicate energy saving potential of 23% to 46% in end uses such as lighting, cooling ventilation, refrigeration, etc. The potential is largely untapped, partly due to lack of effective delivery mechanisms for energy efficiency. In order to achieve untapped potential in the building sector, BEE has published the Energy Conservation Building Code (ECBC) on May 27, 2007. ECBC was developed as a first step towards promoting energy efficiency in building sector, and sets minimum energy performance standards for commercial buildings. ECBC compliant buildings consume 40-60% less energy than conventional buildings. Presently, ECBC is introduced on voluntary basis, however, it is expected to be made mandatory in future for commercial buildings at present having connected load of 500 kW or greater or a contract demand of 600 kVA or greater for efficient use of energy and its conservation.

Commercial buildings can provide great opportunities for the distribution Utilities to take up energy efficiency and fuel switching programmes. Various end uses such as lighting, Heating Ventilation and Air Conditioning (HVAC) and Hot Water Systems are contributing to the system peak demand of the distribution Utility. Design and implementation of DSM programmes such as efficient lighting, thermal storage (generation of chilled water during off-peak period and utilisation of the same during peak period), and installation of new efficient chillers provides immense opportunities to the distribution Utility to reduce the peak demand as well as purchase of costly power purchase during the peak period. Therefore, it is proposed that based on the analysis of load research, the distribution Utilities shall submit proposals for measures such as solar water heating system, thermal storage, etc.

8.6.4 Utilities to undertake the programmes identified by BEE

As explained earlier, under Section 5.9.2 of the National Electricity Policy, BEE has been mandated to initiate Action Plan to implement Demand Side Management and Energy Conservation measures. Further, under Paragraph 5.9.6 states that '*Regulatory Commissions should ensure adherence to energy efficiency standards by utilities*'. Given the fact that the DSM measures identified by the BEE will have to be implemented by the utilities which are under jurisdiction of the SERCs, it is obvious that the SERCs will have to ensure that the utilities undertake the programmes identified by BEE. The Commission is of the view that it is its specific responsibility to ensure that utilities in its jurisdiction undertake energy efficiency and DSM measures identified by BEE with suitable modifications to take into account state and utility specific conditions.

BEE has already identified number of thrust areas such as Agricultural, Municipal, and Residential sectors, which serves as a roadmap for promoting energy efficiency and demand side management at a national level. Agricultural Demand Side Management (Ag DSM) promises immense opportunity in reducing the overall power consumption, improving efficiencies of ground water extraction and reducing the subsidy burden on the States without sacrificing the service obligation. In order to tap these opportunities, BEE has initiated Ag DSM programme in which pump sets efficiency improvement would be carried out through Public Private Partnership (PPP). In this regard, BEE has launched demonstration project in Solapur district. In this programme, four dedicated agricultural feeders with 2046 pumpsets have been identified. BEE has appointed a Consultant for carrying out detailed energy audit and to prepare a Detailed Project Report.

Similar national level programmes have been launched by BEE in the municipal sector with the basic objective to improve overall energy efficiency of the municipal body, which could lead to substantial savings in the electricity consumption, thereby resulting in cost reductions/savings for the Municipal body. This programme initially covers 175 municipalities in the country by conducting energy audits and preparation of detailed project report. ESCOs are being encouraged to take up the implementation of the programme with the help of financial institutions.

Considering this huge untapped potential in the State of Maharashtra, it is proposed that distribution Utilities in the State shall carry out detailed analysis of these national level programmes launched by BEE and undertake the projects with suitable State/Utility specific modifications. It is envisaged that all distribution Utilities while submitting various DSM programmes/plans to the Commission for approval shall also include implementation of national level programmes initiated by BEE.