ABPS INFRASTRUCTURE ADVISORY PRIVATE LIMITED

Draft Approach Paper for

Multi Year Tariff Regulations for FY 2011-12 to FY 2015-16

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.

In order to 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, based on stakeholders' comments and discussions with the MERC.

ABPS Infra submitted the draft Approach Paper to the Commission for its views. The Commission circulated the draft Approach Paper and presentation to identified experts for their comments. The Commission also organised a Consultation with Experts on October 9, 2009.

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 should have begun from April 1, 2010. However, Utilities requested for deferment of the second Control Period by one year, in their comments on the draft Approach Paper on MYT Regulations for the second Control Period. The Commission accepted the request of the stakeholders and hence, the next Control Period of five years will commence on April 1, 2011 and continue upto March 31, 2016.

Based on the comments and suggestions received from the expert group (both, through written submissions and views expressed during the expert consultation meeting held on October 9, 2009) and subsequent discussions with the Commission on various pertinent issues, the Approach Paper has been revised.

The Approach Paper is organised in seven 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

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, 2011 to March 31, 2016. The objectives of any MYT framework are:

- Provide regulatory certainty to the Utilities, investors and consumers by promoting transparency, consistency and predictability of regulatory approach, thereby minimizing the perception of regulatory risk.
- Address the risk sharing mechanism between Utilities 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.
- Promote operational efficiency.
- 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:

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

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 Utilities, 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, Utilities 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.

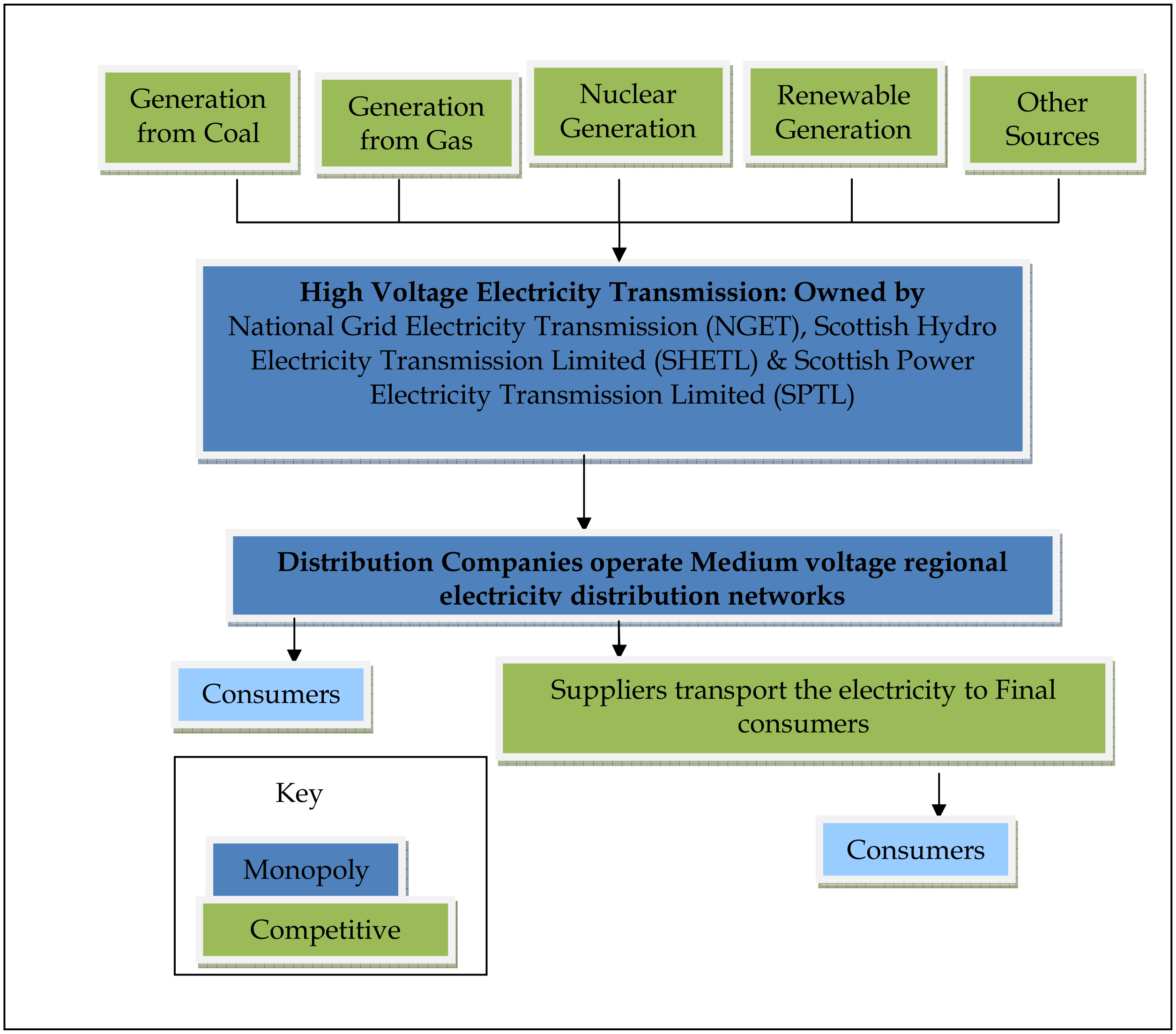
The DNOs, as parties operating on the electricity transmission network, have a role in ensuring that their positions remain in balance and that, in this respect, the volume of electricity that they inject into the system is equivalent to the amount that they draw. The DNOs also have a role in delivering 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:



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, it is felt 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.

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. It was proposed in draft Approach Paper that the Business Plan for the second Control Period may be filed latest by November 30, 2009 for the Commission's approval, and that for the third Control Period, the timelines recommended by FOR would be applicable.

However, in their comments on the draft Approach Paper on MYT Regulations for the second Control Period, several stakeholders requested for additional time for preparation of Business Plan. The Commission accepted the request of the stakeholders for additional time for submission of the Business Plan for the second Control Period and directed Utilities to submit their Business Plan for the second Control Period latest by March 15, 2010.

The Business Plan shall be for a period of six years commencing from FY 2010-11 to FY 2015-16, though the MYT Control Period is for a five-year period from FY 2011-12 to FY 2015-16. The Utilities have separately filed Annual Performance Review Petitions for FY

2009-10, wherein they have projected the expenses and revenue for FY 2010-11. The Business Plan shall contain the sales forecast after considering the effect of proposed load shedding, if any, power procurement plan 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/medium-term/short-term contracts as appropriate 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.

For ensuring uniformity and to provide clarity on the aspects to be addressed in the Business Plan, the structure of the Business Plan and Formats for capturing some of the key aspects, have already been issued by the Commission.

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. However, several stakeholders requested for deferment of the second Control Period by one year, in their comments on the draft Approach Paper on MYT Regulations for the second Control Period, since they wanted additional time to understand the implications of the MYT regime being proposed, which was a significant change from the existing MYT mechanism. The Commission accepted the request of the stakeholders and hence, the next Control Period of five years will commence on April 1, 2011 and continue upto March 31, 2016.

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, 2011 to March 31, 2016.

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, it is felt that benchmarking with the Utility's 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. Variation in 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. Variation in Technical and Commercial losses, including bad debts: 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.

   In the electricity supply business, there is an element of bad debt, due to the risk of 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.

3. Variation in Performance Parameters: Performance 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. Variation in Interest on Working Capital: 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.

5. Variation in 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.

6. 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.

7. Variation in Wires and Supply Availability:

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****.* ***<u>For every 1% under-achievement in composite availability for urban or rural areas, ROE shall be reduced by 0.1% of equity</u>****. 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.

<u>Wires Network Availability</u>

In accordance with the above FOR recommendations, based on past performance of Wires Business of distribution Utilities, it is proposed that the distribution licensees need to ensure Wires Availability of at least 90% and 95% for rural and urban areas, respectively. For every 1% under-achievement in Wires Availability, ROCE rate shall be reduced by 0.1%. Similarly, if there is 1% over-achievement in Wires Availability, ROCE rate shall be increased by 0.1%. Proposed formulae for calculation of Wires Availability, is as under:

Wires Availability = (1- (SAIDI / 8760)) x 100

where

$$\text{SAIDI} = \frac{\text{Sum of all Customer interruption durations}}{\text{Total number of customers served}}$$

Wires Availability is proposed to be measured over the course of a year and will be expressed in percentage terms.

Supply Availability

In accordance with the above FOR recommendations, it is proposed that Supply Availability may be measured on the basis of power contracted by distribution licensees on a long-term or medium-term basis for the power procurement plan submitted by the Utility and may be represented in two sub-heads as under:

1. Base load Supply Availability: This parameter may be used to represent ability of Supply Business to meet its base load requirement. Proposed formula for calculation of this parameter is

   Base load Supply Availability =

   $$\frac{\text{(Actual Contracted Base Load Supply in MW) x (No of Off-Peak hours)}}{\text{(Base load in MW) x (No of off Peak hours)}}$$

2. Peak load Supply Availability: This parameter may be used to represent the ability of the Supply Business to meet its peak load requirement. Proposed formula for calculation of this parameter is

Peak load Supply Availability:

$$\frac{\text{(Actual Contracted Peak Load Supply in MW) x (No of Peak hours)}}{\text{(Peak load in MW) x (No of Peak hours)}}$$

Since the peak hours and off-peak hours could vary from one season to another, the above computations may be done in such a manner that the sum of off-peak hours and peak hours is 8760 hours, i.e., the total number of hours in a year.

It is proposed that Supply Availability will be specified in the respective MYT Order by the Commission based on the Base load Supply Availability and Peak load Supply Availability, with the weightage for Base load Supply Availability and Peak load Supply Availability being considered as, say, 75% and 25%, i.e., greater emphasis may be placed on meeting base load requirements. It is felt that the Supply Availability for base load should be 100% and concession, if any, may be given in the peak load supply availability, since as per the distribution licence conditions, the licensee is supposed to ensure supply on 24 x 7 basis, and there is no specific reference to load shedding under the EA 2003. It is proposed to impose disincentive 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%. Similarly, if there is 1% over-achievement in Supply Availability, ROCE rate shall be increased by 0.1%.

In case the actual supply is higher than the normative level, then the Supplier will be entitled to an incentive, and conversely, if the actual supply is lower than the normative level, then the Supplier will be subjected to a dis-incentive.

Some of the other factors proposed to be considered as controllable, are 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. O&M expenses, which include employee expenses, are proposed to be allowed on a normative basis and also 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. Hence, the O&M expenses are classified as controllable factor.

2.4.2 Uncontrollable factors

Z-factors: Performance based Tariff 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. Interest Expenses: In this context, 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. Hence, interest expense under ROCE approach is proposed to be controllable factor. However, a pass-through under the Z factor shall be allowed under specific circumstances, as mentioned in Chapter-3 of this Approach Paper.
2. Force Majeure events, such as acts of war, fire, natural calamities, etc.
3. Change in law, judicial pronouncements, and Orders of the Central Government, State Government or Commission.
4. Variation in fuel cost on account of variation in coal, oil and all primary/secondary fuel prices.
5. Variation in freight rates.
6. Variation in cost of Power Generation and/or Power Purchase due to additional Short-term Power Purchase :

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 the 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 2008-09	**MSEDCL**				
	Long-term Power Purchase	76431	16941	2.22	98.54%
	Short-term Power Purchase	1136	833	7.33	1.46%
	Total	77567	17774	2.29	

Note: Figures are taken from latest Tariff Orders of RInfra-D, TPC-D, BEST and MSEDCL.

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 2006-07 and FY 2007-08 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."*

At the same time, 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 or medium-term contracts at optimum 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.

It is proposed that the Distribution Licensee shall undertake his power procurement during the year in accordance with the power procurement plan for the Control Period, which may include long-term, medium-term and short-term power procurement approved by the Commission in accordance with these Regulations.

It is proposed that the Distribution Licensee can undertake additional short-term power procurement during the year, over and above the power procurement plan for the Control Period approved by the Commission under the following circumstances:

1. Where there has been a shortfall or failure in the supply of electricity from any approved source of supply during the financial year, the Distribution Licensee may enter into additional short-term arrangement or agreement for procurement of power (short-term means upto a period of one year), provided that if the total power purchase cost for any block of six months including such short-term power procurement exceeds 105% of the power purchase cost approved by the Commission for the respective block of six months, the Distribution Licensee will have to obtain prior approval of the Commission. Further, the proposed short-

term power procurement shall be in accordance with principles specified for Supply Availability.

2. Where the Distribution Licensee has identified a new short-term source of supply from which power can be procured at a tariff that reduces his approved total power procurement cost, the Distribution Licensee may enter into a short-term power procurement agreement or arrangement with such supplier without the prior approval of the Commission.

3. The Distribution Licensee may enter into a short-term arrangement or agreement for procurement of power without the prior approval of the Commission when faced with emergency conditions that threaten the stability of the distribution system or when directed to do so by the State Load Despatch Centre to prevent grid failure.

4. Within fifteen (15) days from the date of entering into an agreement or arrangement for short-term power procurement for which prior approval is not required, the Distribution Licensee shall provide the Commission, full details of such agreement or arrangement, including quantum, tariff calculations, duration, supplier details, method for supplier selection and such other details as the Commission may require with regard to such agreement/arrangement.

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."

The ratio for sharing the gains may be as under:

a. In case of Generation Company or 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 or licensees, may be utilized by the Utility at its discretion.

Gains shall be shared with the consumers at the time of the tariff determination process for the third Control Period.

In the draft Approach Paper, it was proposed to accept the FOR recommendation that 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. However, based on the suggestions received by various stakeholders and subsequent discussions, it is proposed to share losses on part of controllable factors as under:

c. In case of Generation Company or Licensees, one-third of such losses may be passed as an additional charge to the consumers.

d. The balance amount shall be borne by the Generation Companies or licensees

Gains and losses on account of controllable factors during the second Control Period shall be shared with the consumers at the time of Mid-term Performance Review and also at the time of tariff determination process of third Control Period.

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 half yearly basis through the 'Z' factor.

Further, in the first Control Period, the electricity bills of consumers has varied almost every month mainly due to variation in levy of FAC. To provide certainty to consumers, it is proposed that FAC will be revised on half-yearly basis to the consumers. However, to insulate Utilities from this additional cost, it is proposed that carrying cost for under-recovery of FAC for the corresponding period will be allowed as a pass-through under Z-factor.

It is proposed that the approved aggregate gain or loss to the Generating Company or Licensee on account of uncontrollable factors shall be passed through under Z-factor Charge, as an adjustment in the tariff of the Generating Company or Licensee on a half yearly basis, as may be specified in the Order of the Commission passed under these Regulations.

Z-factor Charge Determination

The Generating Company or Licensee shall submit details in the stipulated format to the Commission on a half yearly basis for the Z-factor Charge and, for this purpose, shall submit such details of the variation between expenses incurred and the approved figures by the Commission, along with the detailed computations and supporting documents as may be required for verification by the Commission.

Provided that subsequent to the notification of these Regulations, the Generating Company or Licensee, shall obtain the approval of the Commission prior to levying the Z-factor Charge.

Components of Z-factor Charge:

It is proposed that there will be three components of Z-factor Charge, as under:

$$Z = Z_{FAC} + Z_{G\text{-}sec} + Z_{OUC}$$

Where

Z = Z-factor Charge

Z_{FAC} = Z-factor Charge - component for FAC.

$Z_{G\text{-}sec}$ = Z-factor Charge - component for 10 year G-sec rate variation

Z_{OUC}= Z-factor Charge - component for Variation in any other uncontrollable factors.

A. Fuel surcharge adjustment: Z_{FAC}

a) 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) component of Z-factor Charge.

b) The FAC component shall be applicable on the entire sale of the Distribution Licensee without any exemption to any consumer.

c) The FAC component 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.

1. First Approval of Z-factor Charge in the second Control Period

The Distribution Licensee shall submit details in the stipulated format to the Commission for the first half of the first year of second Control Period, for prior approval of Z-factor charge to be recovered in the second Control Period, as stipulated by the Commission. The Distribution Licensee shall submit the details of fuel costs relating to power generated from own generation stations and variable cost of power procured for first half of the first year of second Control Period, within 60 days of completion of first half.

It is proposed that the Commission shall approve Z-factor Charge for first half of the first year of second Control Period, to be recovered in the second Control Period, subject to prudence check.

2. Subsequent Approval of Z-factor Charge in the second Control Period

The Distribution Licensee shall submit details in the stipulated format to the Commission for the subsequent half yearly periods of the second Control Period, for prior approval of Z-factor charge to be recovered in the ensuing half yearly periods of the second Control Period. The Distribution Licensee shall submit the details of fuel costs relating to power generated from own generation stations and variable cost of power procured for the subsequent half yearly periods of the second Control Period, within 60 days of completion of such half. The Distribution Licensee shall also submit the Z-factor Charge levied to all consumers for the preceding half yearly period vis-a-vis the Z-factor component recoverable, along with the detailed computations and supporting documents as may be required for verification by the Commission.

3. Formulae for FAC component of Z-factor Charge

The formula for the calculation of the FAC component of Z-factor Charge shall be as under:

Z_{FAC} (Rs Crore) = F + C + B,

Where

Z_{FAC} = Z-factor Charge - component for FAC

F=Change in fuel cost of own generation and variable cost of power purchase

C=Carrying Cost for any under recovery/over recovery on account of Change in fuel cost of own generation and variable cost of power purchase

B= Adjustment factor for over-recovery / under-recovery

"F" shall be computed in accordance with the following formula:

F (Rs. Crore) = $\mathbf{A_{FC,Gen} + A_{FC,PP}}$, Where:

$A_{FC,Gen}$: Change in fuel cost of own generation. This change would be computed based on the norms and directives of the Commission, including heat rate, auxiliary consumption, generation and power purchase mix, etc.

$A_{FC,PP}$: 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 MYT Order, and subject to applicable norms.

"C" shall mean carrying cost on account of change in fuel cost of own generation and variable cost of power purchase.

"B" shall be computed in accordance with the following formula:

$\mathbf{B_{Hn}}$ **(Rs. Crore) =** $\mathbf{A_{Hn-1} + R_{Hn}}$

Where:

B_{Hn} = Adjustment factor for over-recovery / under-recovery in the half "n"

A_{Hn-1} = Incremental cost in the half "n-1".

R_{Hn} = Incremental cost in half "n-1" actually recovered in ensuing half "n".

It is proposed that the total $\mathbf{Z_{FAC}}$ recoverable, as per the formula specified above, shall be recovered from the actual sales in "Rupees per kilowatt-hour" terms and $\mathbf{Z_{FAC}}$ shall be recoverable based on estimated sales to such consumers, calculated in accordance with such methodology as may be stipulated by the Commission. If the actual distribution losses of the Distribution Licensee exceed the level approved by the Commission, the amount of $\mathbf{Z_{FAC}}$ corresponding to the excess distribution losses (in kWh terms) shall be deducted from the total $\mathbf{Z_{FAC}}$ recoverable.

Calculation of Z_{FAC} per kWh shall be as per the following formula:

$Z_{FACRs./kWh}$ = (Z / (Metered sales + Unmetered consumption estimates + Excess distribution losses)) * 10

B. Variation in G-sec rate: $Z_{G\text{-}sec}$

In case the 10 year G-sec rate varies vis-à-vis the benchmark rate at the beginning of the year as specified in Chapter-3 of this Approach Paper, then Return on Capital Employed pertaining to variation more than 1% (plus or minus) as compared to benchmark rate, will be a pass-through under Z factor Charge, on a yearly basis, in a manner as stipulated by the Commission.

C. Other components of Z-Factor Charge: Z_{OUC}

In case there is variation in cost for Generating Company or Licensee on account of any other uncontrollable factors, the same shall be pass-through under Z factor Charge, on a yearly basis, in a manner as stipulated by the Commission.

2.6 MYT Framework and Method of calculating Tariff for Second Control Period

The multi-year tariff framework shall be based on the following elements, for calculation of Aggregate Revenue Requirement (ARR) for Transmission and Wheeling business and Tariff for Generating Companies and Retail sale of electricity:

(i) A detailed Business Plan based on the forecast of the aggregate revenue requirement shall be submitted by the Applicant for the Commission's approval based on the prudence check and Operational Norms and trajectories of performance parameters specified in the MYT Regulations, for each year of the Control Period;

(ii) Based on the approved Business Plan, the Applicant shall submit the forecast of Aggregate Revenue Requirement and expected revenue from existing tariffs and charges shall be submitted by the Applicant, and the Commission shall approve the ARR for Transmission and Wheeling business and Tariff for Generating Companies and Retail sale of electricity along-with indexation of indexed parameters, for each year of the Control Period;

(iii) The trajectory for specific variables shall be stipulated by the Commission, where the performance of the Applicant is sought to be improved through incentives and disincentives;

(iv) The Commission shall specify the change in indexation, if required, for indexed parameters as specified in the Regulations, on the 30th day of April of every year of the Control Period, starting from the second year of Control Period and specify change in ARR and Tariff, as applicable to Transmission Business, Wheeling business, Generating Companies and Retail sale of electricity;

(v) Mid-term review of performance vis-à-vis the approved forecast and categorization of variations in performance as those that were caused by factors within the control of the Applicant (controllable factors) and those caused by factors beyond the control of the applicant (uncontrollable factors) shall be undertaken by the Commission;

(vi) The mechanism for pass-through of approved gains or losses on account of uncontrollable factors as specified by the Commission;

(vii) The mechanism for sharing of approved gains or losses arising out of controllable factors as specified by the Commission;

(viii) One-time determination of ARR for Transmission and Wheeling business and Tariff for Generating Companies and Retail sale of electricity, for each financial year within the Control period along with indexation of specific parameters based on the approved forecast, shall be undertaken at the start of the Control Period and also reviewed at the time of the mid-term performance review.

2.6.1 **Applicability**

The multi-year tariff framework shall apply to Applications made for determination of ARR for Transmission and Wheeling business and Tariff for Generating Companies and Retail sale of electricity:

The Commission may specify a trajectory of the specific variables and performance parameters for determination of tariff for:

(i) a generating station/Unit,

(ii) a Generating Company; and/ or

(iii) a Licensee

2.6.2 **Control Period**

The Generating Companies and Licensees shall submit a Business Plan based on the forecast of his Aggregate Revenue Requirement for the approval of the Commission for each financial year within a Control period of five (5) financial years:

Based on the approved Business Plan, the Generating Companies and licensees shall forecast their 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 application made to the Commission under these Regulations, the Control Period shall be five (5) financial years, i.e., April 1, 2011 to March 31, 2016.

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:

2.6.3 **Forecast**

The applicant shall submit the forecast of Aggregate Revenue Requirement and expected revenue from tariff for the Control Period in such manner, within such time limit as provided in MYT Regulations.

<u>Forecast of Aggregate Revenue Requirement</u>

The Applicant shall develop the forecast of Aggregate Revenue Requirement for the Control Period using the following methodology

(a) Assumptions relating to the behaviour of individual variables that comprise the Aggregate Revenue Requirement during the Control Period; or

<u>Forecast of expected revenue from tariff and charges</u>

The Applicant shall develop the forecast of expected revenue from tariff and charges based on the following:

(b) In the case of a Transmission Licensee, estimates of transmission capacity allocated to Transmission System Users for each financial year within the Control Period;

(c) In the case of a Distribution Licensee, estimates of quantum of electricity supplied to consumers and wheeled on behalf of Distribution System Users for each financial year within the Control Period;

(d) Prevailing tariffs as at the date of making the Application.

The Applicant shall provide full details supporting the forecast, including but not limited to details of past performance, proposed initiatives for achieving efficiency or productivity gains, technical studies, contractual arrangements and/or secondary research, to enable the Commission to assess the reasonableness of the forecast.

Upon studying the Application, the Commission shall either-

(a) pass an order approving the ARR/ Tariffs for the Control Period, subject to such modifications and conditions as it may specify in the said Order; or

The Commission shall specify in these Regulations, the variables comprising the Revenue Cap and Price Cap determination of the Applicant that shall be reviewed by the Commission as part of the mid-term performance review.

2.6.4 **Specific trajectory for certain variables**

The Commission may stipulate a trajectory, which may cover one or more Control Periods, for certain variables having regard to the reorganization, restructuring and development of the electricity industry in the State.

Provided that the variables for which a trajectory may be stipulated include, but are not limited to O&M Norms, generating station availability, station heat rate, secondary oil consumption, auxiliary consumption, transit losses, transmission availability, transmission losses, supply availability and distribution network availability, distribution losses and collection efficiency.

The trajectory stipulated by the Commission in the Business Plan shall be incorporated by the Applicant in his forecast of Aggregate Revenue Requirement and/or expected revenue from tariff and charges.

2.6.5 Mid-term review of performance

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, the process of provisional truing up followed by annual truing up 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 expressed the 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. Moreover, as a result of the provisional truing up and final truing up, the ARR of any particular year effectively gets determined three times, viz., first at the time of tariff determination for the prospective year, second at the time of provisional truing up, and third at the time of final truing up.

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

(a) Performance trajectory

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) Cost elements

i. Operation & Maintenance (O&M) expenses have been approved as a whole for Generating Companies, and as 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.

Hence, it is proposed to do away with annual performance review during each year of the Control Period. Instead, it is proposed to undertake Mid-term Performance Review in the third year of the five-year Control Period.

An Application for Mid-term Performance Review shall be made to the Commission not less than one hundred and twenty (120) days before the start of fourth year of the Control Period. 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 Regulations.

The Licensee or Generating Company shall make an application for mid Mid-term Performance Review within the time limit specified in these Regulations.

The Licensee or Generating Company, as the case may be, submit to the Commission information in such form as may be stipulated by the Commission from time to time, together with the Accounting Statements, extracts of books of account and such other details as the Commission may require to assess the reasons for and extent of any variation in financial performance from the approved forecast of aggregate revenue requirement and expected revenue from tariff and charges.

The scope of the Mid-term Performance Review shall be a comparison of the performance of the Generating Company or Licensee with the approved forecast of aggregate revenue requirement and expected revenue from tariff and charges and shall comprise the following:

(a) a comparison of the audited performance of the Applicant for the previous two financial years with the approved forecast for such previous financial year; and

(b) a comparison of the performance of the Applicant for the first half of the current financial year with the approved forecast for the current financial year.

The Applicant shall submit the information required for the mid-term performance review in such form as may be stipulated by the Commission from time to time.

For the efficiency parameters stipulated by the Commission under the MYT Regulations, the Commission shall carry out a detailed review of performance of the Applicant vis-à-vis the approved forecast, as part of the Mid-term Performance Review.

Upon completion of the review under MYT Regulations, the Commission shall attribute any variations or expected variations in performance for variables stipulated , to factors within the control of the Applicant (controllable factors) or to factors beyond the control of the Applicant (uncontrollable factors):

Any variations or expected variations in performance, for variables other than those stipulated under MYT Regulations, shall not be reviewed by the Commission during the Control Period and shall be attributed entirely to controllable factors:

The Applicant or any interested or affected party believes, for any variable not stipulated under MYT Regulations, that there is a material variation or expected variation in performance for any financial year on account of uncontrollable factors, such Applicant or interested or affected party may apply to the Commission for inclusion of such variable at the Commission's discretion, for such financial year.

In case, variation in average 10 year G-sec rate of any completed year in the second Control Period is not more than 1% (plus or minus) vis-à-vis the benchmark rate considered at the beginning of the year, then Return on Capital Employed pertaining to said variation as compared to benchmark rate, as mentioned above, will be considered for determination of ARR and Tariff, as the case may be, at the time of the Mid-term Performance Review.

The Commission shall review an Application in the same manner as the original Application for determination of ARR and Tariff and upon completion of such review, either approve the proposed modification with such changes as it deems appropriate or reject the Application made for reasons to be recorded in writing.

Upon completion of the Mid-term Performance Review, the Commission shall pass an order recording-

(a) the approved aggregate gain or loss to the Generating Company or Licensee on account of controllable factors and the mechanism by which the Generating

Company or Licensee shall pass through such gains or losses in accordance with MYT Regulations.

(b) the approved modifications to the forecast of the Generating Company or Licensee for the remainder 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 2011-12, i.e., April 1, 2011 and onwards up to FY 2015-16, i.e. March 31, 2016. However, for all purposes including the review matters pertaining to the period till FY 2010-11, 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 2011-12 to FY 2015-16 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 three Options for considering the Rate Base, viz.,

1. Return on Equity (ROE) approach, where the Rate Base is equal to the equity or the net-worth invested in the business,
2. Return on Capital Employed (ROCE) approach, where the Rate Base is the total capital employed (Equity and Debt) by the Utility.
3. Distribution Margin (DM) approach, performance based return on equity is provided, over and above minimum return of equity.

   The concept of DM has been provided in the Tariff Policy as a possible basis for allowing returns in distribution businesses. This is entirely different from the DM concept considered in Karnataka in the context of privatisation. FOR has undertaken study on the DM model as envisaged in the Tariff Policy.

3.2 Distribution Margin Approach

In FY 2001-02, DM concept was first introduced in India by the State Government of Karnataka (GoK), as a part of energy reforms policies. GoK had identified DM Approach in context of privatisation of Electricity Supply Companies ("Escoms"), as a part of reform process. The DM Approach was proposed to provide a commercial and regulatory framework for a transition period of privatisation process. During this transition period, it was proposed that some of risks will be allocated to other stakeholders such as the Government and Government owned companies, while some other risks will be mitigated through a number of measures. Once the transition period ends on satisfaction of the preconditions, these risks are proposed to be borne by the investors. Since, this is a new concept it will be important to understand the concept as proposed by State Government of Karnataka.

The DM Approach is a method of providing a predictable, performance based payment for electricity distribution services to the distribution Utility. The DM Approach is designed so that the distribution Utility has a reasonable assurance that it will be able to earn its revenue requirement, provided it meets its performance obligations and targets. Its key features are:

The Distribution Utility is allowed to earn a Distribution Margin as compensation for operating the distribution business satisfactorily. The Distribution Margin has two components; (i) Base Revenue and (ii) Incentive Charge.

Base Revenue: The Base Revenue is the amount of revenue that the Distribution Utility is allowed to retain to meet its cost of operating the distribution business. The Base

Revenue is calculated, taking into account the estimated total first year cost of distribution services, plus a reasonable minimum equity rate of return. This return on equity is below the market expectations for similar businesses in order to incentivise the distribution Utility to earn higher return.

Incentive Charge

The Incentive Charge is a pre defined proportion of the collection (paisa per rupee collected) above a specified minimum collection requirement (called the 'Minimum Collection Requirement' discussed below) that the distribution Utility may be allowed to retain. The Incentive Charge represents the investor's return above the base return on equity fixed as part of the Base Revenue.

The Incentive Charge is designed to maximize total revenues and efficiency of the electricity system by solving the major problems associated with electricity distribution, namely, technical and commercial losses.

Minimum Collection Requirement

The distribution Utility is entrusted with responsibility to collect a minimum gross revenue, or Minimum Collection Requirement (MCR). The MCR is a minimum amount of cash that must be collected by the distribution Utility from consumers for sale of electricity. If the distribution Utility does not achieve the MCR, it must pay a penalty.

Tariff Policy

Clause 5 (a) of the Tariff Policy stipulates:

> *"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."*

FOR report on MYT framework and distribution margin

In this context, the FOR report on MYT framework and distribution margin has analysed the distribution margin model as originally proposed in Karnataka during 2001-02 and concluded that this model could not be adopted and have stated following reasons:

"

- *The scheme will violate many provisions of EA 2003. It will require continuation of the single buyer model, and the concept of open access (OA) and consumer choice would remain on paper only.*
- *No State government will commit provision of unlimited "transitional support", as required in the scheme.*
- *The scheme was designed in the context of privatisation, and its effectiveness and relevance for government owned utilities is questionable.*
- *The Group, however, felt that an MYT framework could be evolved by incorporating some essential features of the DM concept as follows:*
- *MYT framework should consider "supply business" and "network business" of distribution licensee separately. Thus, retail tariff of a distribution licensee should be equal to supply tariff plus network tariff (or distribution margin).*
- *Distribution margin (or network tariff) to recover cost of network (excluding cost allocable for supply tariff).*
- *Distribution margin to reflect capital servicing costs (depreciation and ROE), O&M costs (employee costs,* ***R&M (Author spell out)*** *costs and* ***A&G (Author spell out)*** *costs) and related network businesses (true-ups, incentives, penalties)."*

In addition to above mentioned demerits, this concept does not have a generic applicability for other two segments of electricity sector, viz., generation and transmission business, and is mainly applicable for distribution Utilities only. However, this concept is still under consideration by Forum of Regulators (FOR) and FOR is yet to take a final view on it.

However, for the parallel licence operations, i.e., distribution Utility supplying power through parallel network or using network of other distribution Utility to the consumers, does not have incentive for supplying power to the consumers, as there is no additional return on equity. To encourage parallel licence operations, it is proposed that Distribution Margin can be explored as an alternative. Distribution Margin is proposed to be calculated as minimum allowable ROE per unit of sales in Maharashtra.

Option-I: If ROE approach is adopted

Comparison of minimum allowable ROE per unit of sales allowed by Commission in Maharashtra for distribution Utilities is shown in table below

Table 2: Return on Equity per unit of Sales

ROE/unit **in Paise/unit**

	FY 2007-08	**FY 2008-09**	**FY 2009-10**	**3 year-Average**
MSEDCL	9	9	9	**9**
RInfra-D	21	20	20	**21**
TPC-D	9	9	9	**9**
BEST	25	25	24	**24**

It is clear that ROE per unit of sales is in the range of 9 paise to 25 paise per unit sales. Hence, in Maharashtra, minimum allowable ROE is 9 paise per unit of sales.

Option-II: If ROCE approach is adopted

Comparison of minimum allowable ROCE per unit of sales calculated based on the GFA and accumulated depreciation approved by Commission and taking 12.25% as ROCE allowed, in Maharashtra for distribution Utilities is shown in table below

Table 3: Return on Capital Employed per unit of Sales

ROCE/unit **in Paise/unit**

	FY 2007-08	**FY 2008-09**	**FY 2009-10**	**4 year-Average**
MSEDCL	9	9	9	9
RInfra-D	23	22	29	25
TPC-D	13	15	15	14
BEST	23	24	24	24

It is clear that ROCE per unit of sales is in the range of 9 paise to 25 paise per unit sales. Hence, in Maharashtra, minimum allowable ROCE is 9 paise per unit of sales.

Hence, it is proposed that distribution margin of 9 paise per unit of sales approved by the Commission, may be provided to distribution Utilities. However, the distribution Utility has to choose between ROCE/ROE (as discussed later in this chapter) and Distribution Margin, and accordingly submit MYT Petition for the second Control Period.

Since, the Commission is undertaking a separate study to facilitate operation of parallel distribution licensees in a common operational area in Mumbai, the final recommendation of this study may be taken in to consideration by the Commission at the time of MYT determination process.

3.3 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.

3.4 *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. **Generation Business**

"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 risk-free rate Government Securities (G-sec) rate or with the PLR of public sector banks, 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:

3.5 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.

3.5.1 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 10 year Government Securities (G-sec) rate and also, Prime Lending Rate (PLR) of public sector banks as considered by CERC in its Statement of Objects and Reasons of CERC Tariff Regulations, 2009, may be a better option for arriving at the normative cost of debt. The difference between the G-sec rate/PLR and the lending rate to the Utilities is considered as the spread.

To determine the spread between average interest rate and the G-sec rate/ PLR 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. Average interest rates for each Utility has been computed based on pooled interest rate for all existing and new loans of that Utility. Hence, the weighted average rate for Utility may be lower than the prevailing interest rates, since the loans taken earlier (older loans) may be at a lower interest rate.

Step-2: Compile G-sec rate and PLR of public sector banks for the period from FY 2006-07 to FY 2009-10.

Step-3: Compute spread of pooled actual interest rate for each Utility for the period from FY 2006-07 to FY 2009-10 with respect to G-sec rate and PLR.

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

3.5.1.1 Benchmarking considering G-Sec rate

G-sec rate for period starting from FY 2006-07 till FY 2009-10 is as under:

Year	Average G-sec Rate
FY 2009-10	6.93%
FY 2008-09	7.69%
FY 2007-08	8.01%
FY 2006-07	7.95%
Average G-sec Rate for FY 2006-07 to FY 2009-10	**7.65%**

The average of 12-month G-sec rates for a particular financial year has been considered to arrive at average G-sec rate for that particular year, and this average G-sec rate has been compared with average interest rate approved for the Utility by the Commission, to calculate spread of that year. Average interest rate approved by the Commission considered here for calculating spread for the Utilities includes normative interest on normative loan component approved by the Commission. Average interest rate used tabulated below depicts the average rate at which Utility is able to raise a loan, for the capital expenditure approved by the Commission. The movement of average interest rates of various Utilities in the State vis-à-vis G-sec rates, is as shown in the Tables below:

Table 4: Interest rate comparison for FY 2006-07

Utility	FY 2006-07		
	Average Interest Rate approved by the Commission	**G-Sec**	**Spread of Average Interest rate with respect to G-sec rate**
Distribution Licensees			
RInfra -D	9.42%	7.95%	1.47%
BEST	10.20%	7.95%	2.25%
TPC-D	9.78%	7.95%	1.83%

Utility	FY 2006-07		
	Average Interest Rate approved by the Commission	G-Sec	Spread of Average Interest rate with respect to G-sec rate
MSEDCL	8.45%	7.95%	0.50%
Transmission Licensees			
RInfra -T	9.87%	7.95%	1.92%
TPC-T	9.70%	7.95%	1.75%
MSETCL	9.97%	7.95%	2.02%
Generation Companies/Business			
RInfra -G	9.44%	7.95%	1.49%
TPC-G	9.92%	7.95%	1.97%
MSPGCL	4.83%	7.95%	
Median of Spread for Utilities			**1.83%**

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

Table 5: Interest rate comparison for FY 2007-08

	FY 2007-08		
Utility	Average Interest Rate approved by the Commission	G-Sec	Spread of Average Interest rate with respect to G-sec rate
Distribution Licensees			
RInfra -D	8.90%	8.01%	0.89%
BEST	10.43%	8.01%	2.42%
TPC-D	9.50%	8.01%	1.49%
MSEDCL	9.03%	8.01%	1.02%
Transmission Licensees			
RInfra -T	8.55%	8.01%	0.54%
TPC-T	9.30%	8.01%	1.29%
MSETCL	10.52%	8.01%	2.51%
Generation Companies/Business			
RInfra -G	4.67%	8.01%	
TPC-G	9.79%	8.01%	1.78%
MSPGCL	8.53%	8.01%	0.52%
Median of Spread for Utilities			**1.29%**

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

Table 6: Interest rate comparison for FY 2008-09

	FY 2008-09

Utility	Average Interest Rate approved by the Commission	G-Sec	Spread of Average Interest rate with respect to G-sec rate
Distribution Licensees			
RInfra -D	8.88%	7.69%	1.19%
BEST	10.23%	7.69%	2.54%
TPC-D	10.44%	7.69%	2.75%
MSEDCL	9.23%	7.69%	1.54%
Transmission Licensees			
RInfra -T	9.01%	7.69%	1.32%
TPC-T	10.24%	7.69%	2.55%
MSETCL	12.38%	7.69%	4.69%
Generation Companies/Business			
RInfra -G	8.11%	7.69%	0.42%
TPC-G	10.07%	7.69%	2.38%
MSPGCL	9.30%	7.69%	1.61%
Median of Spread for Utilities			**1.99%**

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

Table 7: Average Interest rate comparison for FY 2006-07 to FY 2008-09

	3-Year Average		
Utility	**Average Interest Rate approved by the Commission**	**G-Sec**	**Spread of Average Interest rate with respect to G-sec rate**
Distribution Licensees			
RInfra -D	9.07%	7.88%	1.18%
BEST	10.29%	7.88%	2.40%
TPC-D	9.91%	7.88%	2.02%
MSEDCL	8.90%	7.88%	1.02%
Transmission Licensees			
RInfra -T	9.15%	7.88%	1.26%
TPC-T	9.75%	7.88%	1.86%
MSETCL	10.96%	7.88%	3.07%
Generation Companies/Business			
RInfra -G	8.77%	7.88%	0.89%
TPC-G	9.93%	7.88%	2.04%
MSPGCL	8.92%	7.88%	1.03%
Median of Spread for Utilities			**1.56%**

The median of average spread is in the 1.56 % above the G-sec rate. Hence, a spread of say 2% vis-à-vis G-sec as on 31st March of previous financial year, would be appropriate, which **translates to an effective cost of debt of 9.88%, say, 10%.**

3.5.1.2 Benchmarking considering PLR of Public Sector Banks

RBI, in its 'Handbook of Statistics of Indian Economy' for FY 2008-09, has compiled the PLR of five major Public Sector Banks as shown in the Table below:

	PLR
Mar-07	12.25% to 12.50%
Mar-08	12.25% to 12.75%
Jan-09	11.50 % to 12.50%

The ceiling of the above range of PLR has been considered for calculating the spread. The movement of average interest rates of various Utilities in the State vis-à-vis PLR, is as shown in the Tables below:

Table 8: Interest rate comparison for FY 2006-07

Utility	FY 2006-07		
	Average Interest Rate approved by the Commission	PLR	Spread of Average Interest rate with respect to PLR
Distribution Licensees			
RInfra -D	9.42%	12.50%	-3.08%
BEST	10.20%	12.50%	-2.30%
TPC-D	9.78%	12.50%	-2.72%
MSEDCL	8.45%	12.50%	-4.05%
Transmission Licensees			
RInfra -T	9.87%	12.50%	-2.63%
TPC-T	9.70%	12.50%	-2.80%
MSETCL	9.97%	12.50%	-2.53%
Generation Companies/Business			
RInfra -G	9.44%	12.50%	-3.06%
TPC-G	9.92%	12.50%	-2.58%
MSPGCL	4.83%	12.50%	
Median of Spread for Utilities			**-2.72%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and RBI Handbook of Statistics on Indian Economy, 2009.

Table 9: Interest rate comparison for FY 2007-08

	FY 2007-08		
Utility	**Average Interest Rate approved by the Commission**	**PLR**	**Spread of Average Interest rate with respect to PLR**
Distribution Licensees			
RInfra -D	8.90%	12.75%	-3.85%
BEST	10.43%	12.75%	-2.32%
TPC-D	9.50%	12.75%	-3.25%
MSEDCL	9.75%	12.75%	-3.00%
Transmission Licensees			
RInfra -T	8.55%	12.75%	-4.20%
TPC-T	9.30%	12.75%	-3.45%
MSETCL	10.52%	12.75%	-2.23%
Generation Companies/Business			
RInfra -G	4.67%	12.75%	
TPC-G	9.79%	12.75%	-2.96%
MSPGCL	8.53%	12.75%	-4.22%
Median of Spread for Utilities			**-3.45%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and RBI Handbook of Statistics on Indian Economy, 2009.

Table 10: Interest rate comparison for FY 2008-09

	FY 2008-09		
Utility	**Average Interest Rate approved by the Commission**	**PLR**	**Spread of Average Interest rate with respect to PLR**
Distribution Licensees			
RInfra -D	8.88%	12.50%	-3.62%
BEST	10.23%	12.50%	-2.27%
TPC-D	10.44%	12.50%	-2.06%
MSEDCL	9.23%	12.50%	-3.27%
Transmission Licensees			
RInfra -T	9.01%	12.50%	-3.49%
TPC-T	10.24%	12.50%	-2.26%
MSETCL	12.38%	12.50%	-0.12%
Generation Companies/Business			
RInfra -G	8.11%	12.50%	-4.39%
TPC-G	10.07%	12.50%	-2.43%

	FY 2008-09		
Utility	**Average Interest Rate approved by the Commission**	**PLR**	**Spread of Average Interest rate with respect to PLR**
MSPGCL	9.30%	12.50%	-3.20%
Median of Spread for Utilities			**-2.82%**

Note: Figures taken from Audited A/c or respective Tariff Orders or ARR Petition of Utilities as available and RBI Handbook of Statistics on Indian Economy, 2009.

Table 11: Average Interest rate comparison for FY 2006-07 to FY 2008-09

	3-Year Average		
Utility	**Average Interest Rate**	**PLR**	**Spread of Average Interest rate with respect to Average PLR**
Distribution Licensees			
RInfra -D	9.07%	12.58%	-3.52%
BEST	10.29%	12.58%	-2.30%
TPC-D	9.91%	12.58%	-2.68%
MSEDCL	8.90%	12.58%	-3.68%
Transmission Licensees			
RInfra -T	9.15%	12.58%	-3.44%
TPC-T	9.75%	12.58%	-2.84%
MSETCL	10.96%	12.58%	-1.63%
Generation Companies/Business			
RInfra -G	8.77%	12.58%	-3.81%
TPC-G	9.93%	12.58%	-2.66%
MSPGCL	7.55%	12.58%	-5.03%
Median of Spread for Utilities			**-3.14%**

The median of average spread is - 3.14 % above the PLR, i.e., there is a negative spread vis-à-vis the PLR. Hence, a spread of say -3% vis-à-vis PLR as on 31st March of previous financial year, would be appropriate, which translates to an effective cost of debt of 9.58%, say, 10%.

Thus, irrespective of the approach used, i.e., G-sec Rate plus spread or PLR plus negative spread, the benchmark interest rate works out to 10%. During the expert consultation, Utilities submitted that cost of debt of 10% seems to be on lower side. It should be noted that the average interest rate considered for calculating spread consists of old as well as new loans, and the cost of debt proposed to be approved will also consist of old as well as new loans. Hence, it will not be appropriate to approve higher cost of debt only on the basis of prevailing cost of debt for new loans. At the same time, since the proportion of new loans will increase every year, as old loans are repaid, the interest rate will start reflecting the interest rate of the new loans. **Hence, the cost of debt proposed for the Control Period is 11%.**

The Commission will notify the benchmark G-sec rate on 30th day of April based on the G-sec rate communicated by Reserve Bank of India, and in case the average G-sec rate of the completed year varies more than 1% (plus or minus) in any year of the Control Period vis-à-vis the benchmark rate considered at the beginning of the year, then interest expenses pertaining to variation more than 1% (plus or minus) wrt benchmark rate, as mentioned above, will be a pass-through under Z factor.

3.5.2 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 draft 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."

In this context, CERC in its Statement of Objects and Reasons of CERC Tariff Regulations, 2009, has stated as under:

"13.10 The Commission allowed rate of return on equity of 16% and 14% for the tariff period 2001-04 and 2004-09 respectively. The PLRs of State Bank of India during 2001 and 2004 were 11.50% and 10.25% respectively. But as on 1st January 2009, the PLR of State Bank of India is 12.25%. After considering the rise in the PLR of the public sector banks, 10-year G-Sec, etc and also in order to help the entities to build up sufficient internal accruals for the purpose of investment in capacity addition and to ensure better cash flow, the Commission considered & deliberated to restore the rate of return at 16% as was existing prior to 1.4.2004. After consultations & deliberations it was decided to increase the base rate from 14% to 15.5% and an additional 0.5% for timely competition as explained below…"

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%"

It is felt 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%.

3.5.3 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.

In this context, CERC in its Statement of Objects and Reasons of CERC Tariff Regulations, 2009, has stated as under:

> ***"12. Debt-Equity Ratio (Regulation 12)***
>
> *12.1 The draft regulation 13 proposed funding pattern in the debt-equity ratio of 70:30 for new projects. The Commission intended that the investors should be free to invest fund in the form of equity as per their own investment plans, even beyond 30%. If the equity actually invested in a project was more than 30%, it was proposed that equity in excess of 30% would be considered as normative loan. However, where equity deployed was less than 30%, it was proposed to consider actual equity for determination of tariff. In respect of the existing projects, the Commission proposed to retain the same debt-equity ratio as was approved by the Commission in tariff determination as on 31.3.2009. It was further proposed that the expenditure on additional capital expenditure and renovation and modernization would be serviced in the ratio of 70:30.*
>
> *12.2 The proposed debt-equity ratio of 70:30 for new projects has got wide acceptance. The beneficiaries like MPPTCL, GRIDCO, UPPCL, BSEB and individual consumers like Er. R. B. Sharma are of the view that debt-equity ratio of existing projects should also be modified to 70:30. UPPCL, BSES Rajdhani and TNEB have proposed debt-equity ratio of 80:20 for new projects. KSEB proposed debt-equity ratio of 70:30 for generation projects and 80:20 for transmission projects. OPTCL has proposed a high gearing of 90:10 for all new projects. The generating utilities like THDC and NHDC and the transmission utilities like PGCIL have proposed normative debt-equity ratio of 70:30.*
>
> *12.3 The Commission after considering the responses and suggestions is of the view that so far as the existing projects are concerned, the investors have made investments in the existing projects on the basis of the provisions of the existing tariff regulations and any change in the debt-equity ratio of such projects would lead to regulatory uncertainty and*

jeopardize the scenario of investment in power sector. As such the Commission decided not to incorporate any changes in the debt-equity ratio of the existing projects. In keeping with the requirement of tariff policy, the Commission considered it appropriate to include a provision to the effect that equity invested in foreign currency should be designated in Indian rupees on the date of investment. The purpose is to ensure that the debt equity ratio remains unaffected by the foreign exchange rate variation and provide regulatory certainty. Accordingly, a second proviso has been added to clause (1) of Regulation 12 pertaining to debt-equity ratio in these regulations:

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

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.

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

a) 10 year G-sec rate + 4.50 %, for Generating Companies, Transmission Licensees, and Distribution Wires Licensee/Business,

b) 10 year G-sec rate + 5.00 %, for Retail Supply Licensee/Business.

The Commission will notify the benchmark 10 year G-sec rate on 30th day of April of every based on the 10 year G-sec rate communicated by Reserve Bank of India, and in case the average 10 year G-sec rate of the completed year varies more than 1% (plus or minus) in any year of the Control Period vis-à-vis the benchmark rate considered at the beginning of the year, then Return on Capital employed pertaining to variation more than 1% (plus or minus) as compared to benchmark rate, as mentioned above, will be a pass-through under Z factor Charge

3.5.4 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.

In this context, CERC in its Statement of Objects and Reasons of CERC Tariff Regulations, 2009, has stated as under:

"14.2 The issue of allowing post-tax rate of return or pre-tax rate of return was raised in public hearing as well as written submissions. The generating companies and transmission licensees are in favor of retaining existing regulation. In other words, they are of the view that all the risks pertaining to tax on income from core business including incentive, efficiency gain, income on UI, etc should be passed on to the beneficiaries. On the other hand, beneficiaries want that income tax burden to the extent of normal return on equity should only be passed on to the beneficiaries and any proportion of income tax on account of income other than return on equity, like income accrued due to efficiency gain, incentive, UI, normative expenditure, etc should be borne by the utilities themselves.

14.3 Under post-tax rate of return on equity the beneficiaries are paying tax on the net income of the utilities and the tax burden is calculated by grossing up. Considering the present tax rate of 33.99% applicable to the company's form of business, under grossing up methodology, the tax burden becomes almost 50% of the net income of the utility. The beneficiaries are not against refunding income tax to the utilities on the admitted return on equity. The beneficiaries also do not have any objection if the utilities run their business more efficiently and thereby optimize their annual income provided no further cost on account of income tax on income other than admitted return on equity is passed on to them. From the utilities point of view, in a regulated business, the tax burden is reimbursed from the beneficiaries or the consumers on no profit and no loss basis. Consumers pay for the income tax only when it is actually levied on the utilities. In case of any refund of income tax, the same is also passed on to the beneficiaries. Under existing regulation, even the benefit of income tax holiday under section 80IA of the Income Tax Act, 1961 is passed on to the beneficiaries. This benefit of income tax holiday is available to the investors only for development of infra-structure facilities. In case, the passing on the tax burden to the beneficiaries is restricted only to the return on equity component, there is no logic in passing on the benefit of income tax holiday under section 80IA of the Income Tax Act, 1961 to the beneficiaries.

14.4 The Commission, after considering all the views of all stakeholders is of the view that it will be appropriate to move to the system of pre-tax rate of return on equity from the existing post-tax rate of return on equity. Accordingly, the Commission has decided to allow pre-tax rate of return on equity to the utilities. The same shall be calculated by considering the applicable tax rate for the companies for the year 2008-09 as per the relevant Finance Act, as base rate. To give an example:

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

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

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

Rate of pre-tax return on equity = 15.50/ (1-0.3399) = 23.481%.

14.5 In order to facilitate computation of pre-tax, illustrative examples on the above lines have been given in clause 4 of Regulation 15 of these regulations.

14.6 With this change, the beneficiaries will be required to meet the Income Tax liability limited to the equity of the project, considered for tariff purposes and not on other incomes, such as incentive, profit arising out of efficiency improvement, UI Income and the like."

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, it may not be 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, which can be achieved by opting for pre-tax ROCE mechanism, without however, grossing up the return with the applicable income tax rate, as done by CERC.

Hence, pre-tax ROCE proposed to be allowed during the second Control Period is as under:

a) **10 year G-sec rate + 4.50 %, for Generating Companies, Transmission Licensees, and Distribution Wires Licensee/Business,**

b) **10 year G-sec rate + 5.00 %, for Retail Supply Licensee/Business.**

The Commission will notify the benchmark 10 year G-sec rate on 30th day of April based on the 10 year G-sec rate communicated by Reserve Bank of India, and in case the average 10 year G-sec rate of the completed year varies more than 1% (plus or minus) in any year of the Control Period vis-à-vis the benchmark rate considered at the beginning of the year, then Return on Capital employed pertaining to variation more than 1% (plus or minus) as compared to benchmark rate, as mentioned above, will be a pass-through under Z factor Charge

3.5.5 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:

$\mathbf{ROCE_i = WACC_i \; X \; RRB_i}$

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.

3.6 *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 as a part of Business Plan, 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 12: 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%**
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 13: 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
	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

Utility		FY 2007-08	FY 2008-09	FY 2009-10
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
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 14: 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 15 : 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 quite high.

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) Any expenditure on replacement, renovation and modernization or extension of life of old fixed assets, as applicable to Generating Companies and Licensees, shall be considered after writing off the net value of such replaced assets from the original capital cost, to be calculated as follows:

   Net Value of Replaced Assets = OCFA – AD – CC;

   Where;

   OCFA: Original Capital Cost of Replaced Assets;

   AD: Accumulated depreciation pertaining to the Replaced Assets;

   CC: Total Consumer Contributions pertaining to the Replaced Assets

   Explanation – for the purpose of these Regulations, the term renovation and modernization shall have the same meaning as in Section 80 IA of the Income-tax Act, 1961.

d) 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.

e) 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 where 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.

The draft Approach Paper had proposed that in order to limit the impact of Capex related expenses on the total Revenue Requirement of the Utility, there should be a cap on capex related expenses, i.e., capex related expenses should not be more than 5%of ACoS of that financial year or in absolute terms should not be more than 20-25 paise /unit. However, during the expert consultation process, the Utilities submitted that such a cap will not be appropriate and it will limit their ability to undertake infrastructure development. It is proposed to allow the impact of Capex through the ARR, if the Utilities are able to demonstrate the benefits to consumers, which were promised at the outset. Hence, no cap on capex related expenses is proposed.

3.7 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**)*

In this context, CERC in its Statement of Objects and Reasons of CERC Tariff Regulations, 2009, has stated as under:

> *"16.14 Accordingly, the Commission feels that the loan repayment period be treated as 12 years for all normative loans and accordingly this repayment period of 12 years be linked to depreciation. For 12 years during which the loan capital would be refunded to the investors in the form of depreciation, the rate of depreciation shall be as specified in appendix-III of the regulation and thereafter the remaining depreciable value shall be spread over the balance useful life of the assets.*
>
> *16.15 In regard to the rates of depreciation, it has been stated in the Tariff Policy that the depreciation rates for the assets shall be specified by the Central Electricity Regulatory Commission and this rate of depreciation shall be applicable for the purpose of tariff as well as accounting. In fact some of the countries have prescribed Uniform System of Accounts (USoA) for the regulatory entities to bring in uniformity in their system of accounts. Some of the utilities have proposed to adopt the provision of Schedule XIV of the Companies Act, 1956 directly for tariff calculation. Schedule XIV does not have specific rate of depreciation that can be applied directly for generation, transmission and distribution assets used in electricity business. Some of the generating companies are using the rates specified for plants and machineries under continuous operation in schedule XIV to their thermal generating assets for the purpose of accounting whereas hydro generating companies and transmission licensees are applying the depreciation rates specified by the Commission for the purpose of accounting as well as tariff. As per the Companies Act, 1956 the revalued cost of the assets can be the value base for calculation of depreciation whereas for determination of tariff depreciation is calculated on the capital cost admitted by the Commission and do not allow the revalued cost of the assets. The Companies Act, 1956 also allows calculation of depreciation when the asset is ready for use whereas under regulatory system depreciation is calculated only when the asset is put to use. There are also some other differences between the Companies Act, 1956 and regulatory system in calculation of depreciation, like, inclusion of spares in the value base, consideration of salvage value, etc. As the Companies Act, 1956 does not provide specific rate of depreciation that can be applied directly for generation, transmission and distribution assets used in electricity business; it will not be possible to maintain uniformity in calculation of depreciation amongst the various utilities in electricity business.*
>
> *16.16 It has been the practice since 1948 to specify rates of depreciation for various assets used in electricity business separately either by Government of India or the Commission.*

So, in order to bring an uniformity in the rates of depreciation, while providing a higher rates of depreciation during the initial years of useful life of the projects, the Commission decides to specify rates of depreciation for various assets in a separate schedule. ***The depreciation rates for different assets have been so assigned as to arrive at the weighted average rate approximating*** **5.28%**. *The depreciation rates as given in Appendix-III of the regulation have no bearing on the useful life of the projects as defined in regulation 3(42).*

*16.17 During hearing some of the developers like NHDC, SJVNL, THDC indicated that the land which gets submerged and used for reservoir are not capable of being reclaimed or retrieved and hence cost of such land should be treated as depreciable asset. Normally land is considered to be a non-depreciable asset for accounting purposes. However, due to the peculiar nature of hydro project where the land area gets submerged and land used for reservoir are not available for any other use, the Commission considered the request to be genuine and accordingly decided that land other than the land held under lease and the land for reservoir in case of hydro generating stations shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing the depreciable value of the assets."(**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-I of this Approach Paper.

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 average of opening and closing Gross Fixed Assets 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.

However, depreciation will be re-calculated during truing-up for assets capitalised at the time of Mid-term Performance Review or at the time of final truing up during determination of tariff for third Control Period, based on documentary evidence of asset capitalised by the Applicant, subject to the prudence check of the Commission, such that the depreciation is calculated proportionately from the date of capitalisation.

3.8 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.

The monthly coal reports published by Central Electricity Authority (CEA) have been referred to compile data on actual stock days for thermal power stations in Maharashtra, as summarised below:

Table 16: 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.

3.9 Adjustment of Contribution to Contingency Reserve

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."

However, it is felt that the contribution to contingency reserve accumulated till April 1, 2011, may be utilised to set-off some part of revenue gap for the second Control Period. It is proposed that this provisioning be discontinued for the second Control Period.

One issue that needs some clarity is that whether diminution in the value of contingency reserve can be allowed to Utilities or not. The MERC Tariff Regulations 2005, clearly specifies that contingency reserves needs to be invested in securities authorized under the Indian Trusts Act, 1882 within a period of six months of the close of the financial year. The objective of the investment in contingency reserve is to ensure that the desired funds are available when needed, and that there is no diminution in the reserves. Hence, there is no question of diminution in value of contingency reserve. Utilities should not have invested the contingency reserve amount in market linked instruments such as mutual funds, etc., since this risk cannot be passed on to consumers.

3.10 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) <u>O&M Expenses</u>: 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) <u>Depreciation</u>: 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 Chapter 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 Chapter 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 Sector 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.

In case of the hydro generating stations being awarded to a developer (not being a State controlled or owned company), CERC in its Tariff Regulations, 2009 has specified as under:

> *"Provided also that in case the site of a hydro generating station is awarded to a developer (not being a State controlled or owned company), by a State Government by following a two stage transparent process of bidding, any expenditure incurred or committed to be incurred by the project developer for getting the project site allotted shall not be included in the capital cost:*
>
> > *Provided also that the capital cost in case of such hydro generating station shall include:*
> >
> > *(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and*
> >
> > *(b) cost of the developer's 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area:"*

It is felt that any costs incurred by the Project Developer for getting the Project, including costs incurred for bidding purposes, cannot be considered as part of Project cost, as the Developer has to absorb such cost if he does not win the Project. Further, the premium payable to the State Government for getting the Project also cannot be considered as part of Project Cost, as consideration of the same may result in the Developers quoting very high premium to win the Project, which will increase the overall cost of generation of such projects. Accordingly, it is proposed to consider the above provisions as per CERC Tariff Regulations, 2009 in case of hydro generating station being awarded to a developer (not being a State controlled or owned company), .

As discussed in Chapter 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 Renovation and Modernisation

As regards Renovation and Modernisation, the National Electricity Policy of Government of India provides as follows:

> *"5.2.21 – One of the major achievements of power sector has been significant increase in availability and plant load factor of thermal power stations specially over the last few years. Renovation and modernisation for achieving high efficiency levels needs to be pursued vigorously and all existing generation capacity should be brought to minimum acceptable standards. The Govt. of India is providing financial support for this purpose.*
>
> *5.2.22 For projects performing below acceptable standards, R&M should be undertaken as per well defined plans featuring necessary cost - benefit analysis. If economic operation does not appear feasible through R&M, then there may be no alternative to closure of such plants as the last resort.*
>
> *5.2.23 In cases of plants with poor O&M record and persisting operational problems, alternative strategies including change of management may need to be considered so as to improve the efficiency to acceptable levels of these power stations."*

Para 5 (g) of the Tariff Policy notified by the Government of India stipulates as under:

> *"Renovation and modernization (it shall not include periodic overhauls) for higher efficiency levels needs to be encouraged. A multi year tariff (MYT) framework may be prescribed which should also cover capital investments necessary for renovation and modernisation and an incentive framework to share the benefits of efficiency improvement*

between the utilities and the beneficiaries with reference to revised and specific performance norms to be fixed by appropriate Commission. Appropriate capital costs required for pre-determined efficiency gains and/or for sustenance of high level performance would need to be assessed by appropriate Commission."

The expected or rated 'useful' life of power plants has historically been considered as 25 years for Thermal Generating Stations, 35 years for Hydel Generating Stations, and 15 years for Gas Turbine based Generation Stations. For the purpose of tariff, this denotes the period over which 90% of the capital cost is allowed to be recovered through depreciation. Among the power plants, tariff determination of which is in the Commission's jurisdiction, All the units of Bhusawal Thermal Power Stations (TPS) and Koradi TPS thermal power plants owned by MSPGCL have already outlived their initial rated 'useful' life.

Further, many of Units of the power stations owned by MSPGCL and Unit -5 owned by TPC-G has also now been in operation for more than 25 years. In view of this, it has been felt necessary to lay down the principles regarding R&M beyond the original useful life.

As the plant approaches the end of its specified rated 'useful' life, the outage may gradually increase due to wear and tear, and the plants may require increased maintenance and spares. Besides the reduction in plant availability, its energy conversion efficiency, i.e., station heat rate, may also deteriorate. However, the status does not suddenly change in any way on the day the plant completes its rated 'useful' life. The plant continues to operate, and the gradual changes mentioned earlier also continue.

Presently, capital expenditure of essential nature including Renovation and Modernisation after useful life is allowed through the capex approval process. Based on the Detailed Project Report submitted by the Generating Company, the Commission first grants in-principal approval of the capex for the Renovation and Modernisation. Subsequently based on the actual expenditure subject to prudence check, the Commission approves the Capital Expenditure which is added to the the Gross Fixed Assets.

At the end of 'useful' life of the plant, following three options are available with the Generating Company:

(i) Keep the plant in operation at deteriorated efficiency, availability and reliability with increasing O&M cost and with risk of catastrophic failure;

(ii) Scrap the plant and replace it with a new plant;

(iii) Extend its beneficial life through a planned one time Renovation and Modernisation.

Renovation and Modernisation plan with definite life extension is a major exercise requiring detailed planning. and. Even the costs involved undergo change to some extent when the actual works are undertaken. For a poorly maintained plant, Renovation and Modernisation results in better efficiency and performance. On the other hand, in case of an well maintained old plant, just enhanced repair and maintenance may be adequate to maintain the performance and efficiency.

The decision for Renovation & Modernisation (R&M) has to be primarily based on comprehensive techno-economic considerations, after carrying out the required Residual Life Assessment (RLA) study and cost-benefit analysis. The Generating Company is, therefore, required to come up with a detailed proposal for in-principle approval with estimation of R&M expenditure along with cost benefit analysis and definite extended life from a reference date and if in-principle approval is granted, the Commission may allow the prudently incurred Renovation and Modernisation expenditure to be included in the capital cost for the purpose of tariff during extended life.

While it is important that the plant owner is duly compensated for any fresh investment and risks, it is equally important that the consumers pay according to the benefits derived from the plant in future years.

The Central Electricity Regulatory Commission (CERC) vide its Regulation 10 of CERC (Terms and Conditions of Tariff) Regulations, 2009 has specified the following related to Renovation and Modernisation:

"(1) The generating company or the transmission licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the useful life of the generating station or a unit thereof or the transmission system, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of

expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, record of consultation with beneficiaries and any other information considered to be relevant by the generating company or the transmission licensee:

Provided that in case of coal-based/lignite fired thermal generating station, the generating company, may, in its discretion, avail of a 'special allowance' in accordance with the norms specified in clause (4), as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof, and in such an event revision of the capital cost shall not be considered and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided also that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

(2) Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and modernisation, the approval shall be granted after due consideration of reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

(3) Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

(4) A generating company on opting for the alternative in the first proviso to clause (1) of this regulation, for a coal-based/lignite fired thermal generating station, shall be allowed special allowance @ Rs. 5 lakh/MW/year in 2009-10 and thereafter escalated @ 5.72% every year during the tariff period 2009-14, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a unit in commercial operation for more than 25 years as on 1.4.2009, this allowance shall be admissible from the year 2009-10."

As regards Renovation & Modernisation expenses, the MERC (Terms and Conditions of Tariff) Regulations, 2005 specify as under:

"Any expenditure on replacement, renovation and modernization or extension of life of old fixed assets shall be considered after writing off the gross value of any such replaced assets from the original capital cost:

Explanation – for the purpose of these Regulations, the term renovation and modernization shall have the same meaning as in Section 80 IA of the Income-tax Act, 1961. "

It is suggested that the following two options may be provided to the Generating Companies for Renovation & Modernisation of the Generating Units/Stations:

Option-1:

The Generating Company, for meeting the expenditure on Renovation & Modernisation for the purpose of extension of life beyond the useful life of the generating station or a unit thereof, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, proposed means of finance, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, record of consultation with beneficiaries and any other information considered to be relevant by the Generating Company.

Option-2:

The generating company, can avail a 'special allowance' as compensation for meeting the requirement of expenses including Renovation & Modernisation beyond the useful life of the generating station or a Unit thereof, and in such an event, approval of the capital cost shall not be considered and the operational norms shall not be relaxed but the special allowance shall be included in the annual fixed charges. In this option, the Generating Companies, in case of thermal generating stations, may be allowed special allowance of Rs. 5 Lakh/MW/year in FY 2011-12 and thereafter, escalated @ 5.72%

every year during the next Control Period from FY 2011-12 to FY 2015-16, on the similar lines as specified by CERC, so that the plant owner remains incentivised to maintain the Unit/Stations availability at a good level after its useful life.

4.1.3 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 Renovation & Modernisation 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
- O&M Expenses
- Return on Capital Employed
- Interest on Working Capital

  Less:
- Less non tariff income

4.1.4 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/Unit 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/Unit 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.

As regards the normative availability for full recovery of fixed charges, it is suggested that 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 for all Unit/Stations, which have performed better than the norm of 80% as specified in the MERC Tariff Regulations, 2005. As regards the normative availability for generating Unit/Stations of MSPGCL, it is proposed to consider the same based on recommendations by CPRI, in its study. CPRI has made the following recommendations in this regard:

"...The following observations and recommendations can be made from the Table and Figures:

- *i.* *Koradi units (1-4) have never exceeded 80 % PLF in their lifetime in spite of de-rating. As per steady trends in Figure 3, the Units the achievable PLFs are around 65%.*
- *ii.* *As per the trends Nasik units (1-2) are capable of achieving PLFs of around 75% after de-rating.*
- *iii.* *Bhusawal (Unit 1), Paras (Unit 2) and Parli units (1 & 2) are capable of achieving PLF of 80%.*

Units of 210 MW and above can easily achieve the PLF of 80 % with focused attention on coal quality, R&M programs, adherence to planned maintenance schedule, leakage control, operational optimization, etc."

Accordingly, it is suggested that the target availability for MSPGCL's stations may be specified based on the CPRI recommendations as given in following Table:

Unit No.	Koradi		Khaperkheda		Chandrapur		Nashik		Bhusawal		Paras		Parli	
	Cap. MW	Avl. %	Cap. MW	Avl. %	Cap. MW	Avl. %	Cap. MW	Avl. %	Cap. MW	Avl. %	Cap. MW	Avl. %	Cap. MW	Avl. %
1	105	65	210	80	210	80	125	75	62.5	80	62.5	80	20	80

Unit No.	Koradi		Khaperkheda		Chandrapur		Nashik		Bhusawal		Paras		Parli	
	Cap.	**Avl.**	**Cap.**	**Avl.**	**Cap.**	**Avl.**	**Cap.**	**Avl.**	**Cap.**	**Avl.**	**Cap.**	**Avl.**	**Cap.**	**Avl.**
	MW	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
2	105	65	210	80	210	80	125	75	210	80			20	80
3	105	65	210	80	210	80	210	80	210	80			210	80
4	105	65	210	80	210	80	210	80					210	80
5	200	80			500	80	210	80					210	80
6	210	80			500	80								
7	210	80			500	80								
Wt. Avg.	**1040**	**72.41**	**840**	**80.00**	**2340**	**80.00**	**880**	**78.58**	**482.5**	**80.00**	**62.5**	**80.00**	**670**	**80.00**

Further, as regards incentive, it is proposed to provide incentive linked to actual generation as discussed later in this Chapter.

During the expert consultation process, the Generation Companies submitted that shortage of fuel particularly coal, needs to be considered while fixing the norm for target availability. As regards the consideration of shortage of fuel for computing target availability, it is felt that it is the Generating Company's responsibility to ensure adequate supply for fuel. Further, it should be noted that under Case-I bidding also, the Generating Companies have to arrange for fuel and they have not been protected for shortage of fuel.

However, it is suggested that in case of nation-wide shortage of fuel, the Commission may consider relaxation in the target availability on case to case basis during the mid term review or at the end of the Control Period as appropriate.

As the demand of Distribution Licensees varies during different months of the year, it may be possible that during certain months, though the generating Unit/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 Unit/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.

4.1.5 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**

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

4.1.6.1 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 Unit/Stations to be commissioned after the date of effectiveness of the MERC MYT Regulations.

4.1.6.2 Station Heat Rate

For new generating Unit/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.

4.1.6.3 Auxiliary Consumption

For new generating Unit/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 Unit/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 Unit/Stations till the actual performance data for at least 2-3 years is available in this regard. Therefore, it is suggested that auxiliary consumption for Unit/Stations which commissions the FGD Plant after the date of effectiveness of the MERC MYT Regulations may be approved on case to case basis.

4.1.6.4 Transit Loss

During the expert consultation process, Generating Companies submitted that CERC Regulations do not specifically exclude imported coal for allowing transit loss and submitted that zero transit loss as reported by other Generating Companies on imported coal could be on account of accounting system (wherein the losses are included in consumption) or contractual arrangement (delivery basis). Procurement of coal on delivery basis amounts to inland sale and would attract additional taxes. Thus contracting on delivery basis is not in the interest of consumers. It was further suggested that study of the advantages and disadvantages of contracting imported coal on delivery basis should be done and if such analysis indicate a lower cost of procurement, all generating companies shall follow the same.

The concept of allowing transit loss separately is applicable particularly for procurement of domestic coal from Coal India Limited (CIL) as the CIL measures and charges for quantity of coal at the loading point. However, if the coal is being procured on delivery basis, no transit losses shall be applicable. Accordingly, it is suggested that in case of procurement of coal on delivery basis, no transit loss may be allowed and in cases where the coal is procured on the basis of measurement at loading point, normative transit loss may be allowed.

It is suggested that the transit loss norms for new generating Unit/Stations 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:

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 coal including washed coal and imported coal.

4.1.6.5 Secondary Fuel Oil Consumption

For new generating Unit/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

4.1.7 Norms for Generating Unit/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

There are only three generating Units, which have achieved commissioning after the effectiveness of MERC Tariff Regulations, 2005, i.e., Unit-8 of TPC-G, Paras Unit No. 3 and Parli Unit No. 6 of MSPGCL.

During the expert consultation process, the Generating Companies submitted the categorization of plants and the performance norms for Generating Unit/Stations commissioned before and after the date of effectiveness of MERC Tariff Regulations, 2005 proposed in the draft Approach Paper is unwarranted in view of stipulation of Tariff Policy under Clause 5.3 (f) and CERC has also not specified such categorization of existing plants.

As regards the categorisation of plants, CERC, in its Tariff Regulations, 2009 has categorised the plants in two categories, i.e., plants commissioned before the effectiveness of said Regulations and plants to be commissioned after the effectiveness of the said Regulations. Hence, considering the views expressed by the Utilities, it is suggested that generating stations may be classified under two categories, viz., new Units/Stations commissioned and expected to be commissioned before the date of effectiveness of the MERC MYT Regulations, and Units/Stations commissioned after the date of effectiveness of the MERC MYT Regulations.

4.1.8 Norms for Existing Generating Unit/Stations – Existing before the date of effectiveness of MERC MYT Regulations.

As regards the performance parameters to be specified for the existing generating Unit/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 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. The study of CPRI has been completed and accordingly, it is suggested that for existing stations of MSGPCL, the norms may be approved based on the recommendations made by CPRI.

The Commission has also emphasised on benchmarking the performance parameters for the generating Unit/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 utilise multiple fuels, whereas most of the other generating Unit/Stations in the State of Maharashtra and other States are not designed to utilise multiple fuels. Therefore, the comparison of TPC-G's generation Units with other generating stations would not be appropriate.

As the actual Station Heat Rate achieved for Unit-5 of TPC was higher than the heat rate approved in the MYT Order, for assessment of actual and achievable performance parameters for Unit-5 of TPC-G, the Commission appointed CPRI to carry out a detailed study of the various performance parameters. The study of CPRI has been completed and therefore, it is suggested that for Unit-5 of TPC-G, the norms may be approved based on the recommendations made by CPRI.

For RInfra-G Dahanu station, a detailed comparison of performance parameters with similar size and similar vintage stations has been discussed in the subsequent paragraphs.

4.1.8.1 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, 2005, 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

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."

The comparison of the past performance of the generating stations in the State of Maharashtra and comparison of the performance of the stations in the State with generating stations in another States has been discussed below.

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.

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 Budge	West Bengal	2x250	1997-99	Coal	10-12		2460	2468	2472

Source: SERC Tariff Orders and ABPS Infra Analysis

The station heat rate of DTPS has been compared 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.

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.

As regards the norms for station heat rate, Generation Companies have suggested to consider the heat rate data for five years, i.e., from FY 2004-05 to FY 2008-09, which will facilitate at arriving at the midpoint, i.e., FY 2006-07. They suggested that the average actual heat rates for the 5 year period should be compared with the average of the approved values for the corresponding years. In case the average of actual values is less than the average of the approved values, the heat rate at the midpoint could be taken as average actual heat rate plus plus $1/3^{rd}$ of the difference (as the consumer has paid at the heat rate of actual $+2/3^{rd}$ of the difference). Further, degradation can be applied to such arrived heat rate at midpoint for approving the year-wise heat rate for the second Control Period. This approach will tighten the existing norms and will provide incentive to the generating stations.

TPC-G has submitted that in the recent past it has been procuring gas in substantial quantity and it proposes to use the same for Unit-6 also. It was further submitted that Unit-6 is an oil based Unit and the actual heat rate for this Unit is based on oil firing. TPC-G submitted that as heat rate is a combination of boiler efficiency and turbine cycle efficiency, the heat rate would too be adversely affected with increase in utilisation of gas and therefore requested for correction in heat rate on account of gas firing. TPC-G submitted that it had engaged IIT Bombay to determine the gas firing on the boiler efficiency and based on the study it is observed that the boiler efficiency deteriorates by about 3% with gas firing and accordingly it has requested for correction in heat rate by 3%.

The Generating Companies also submitted that the norms should be fixed for group of "similarly" placed entities which defines the "Industry standards" for plants of similar size and vintage to benchmark and improve the norm.

It is suggested that the norms for the station heat rate for existing generating stations which are performing better than the norms as specified in the MERC Tariff Regulations, 2005 may be considered based on the suggestion made that the average actual heat rates for the 5 year period should be compared with the average of the approved values for the corresponding years. In case the average of actual values is less than the average of the approved values, the heat rate at the midpoint could be taken as average actual heat rate plus plus 1/3rd of the difference (as the consumer has paid at the heat rate of actual +2/3rd of the difference). Further, degradation can be applied to such arrived heat rate at midpoint for approving the year-wise heat rate for the second Control Period. As regards the request for correction in the heat rate for Unit-6 on account of use of gas, it is suggested that the same may be considered based on the submission of TPC-G and accordingly the heat rate for Unit 6 has been increased. Based on the above philosophy it is suggested to propose the station heat rate norms for existing generating stations which are performing better than the norms as specified in the MERC Tariff Regulations, 2005 as under:

Station	Unit	Avg. of actual heat rate FY 05 to FY 09	Avg. of approved heat rates FY 05 to FY 09	Eff.gain/ (loss)	Avg. considered for FY 07	FY 07	FY 08	FY 09	FY 10	FY11
		1	2	3=2-1	4=min(1,2)	5=4+3	6=5/(1-0.2%)	7=6/(1-0.2%)	8=7/(1-0.2%)	9=8/(1-0.2%)
Trombay	Unit 4	2536	2563	27	2536	2545	2550	2555	2560	2565
	Unit 6	2327	2365	38	2327	2339	2344	2349	2353	2358
	Unit 7	1999	1978	-22	1978	1999	2003	2007	2011	2015
Dahanu	Unit-1 & -2	2285	2421	136	2285	2285	2290	2294	2299	2303
Uran		1989	1980	-8	1980	1989	1993	1997	2001	2005

Station		FY12	FY13	FY14	FY15	FY16
Trombay	Unit 4	2570	2576	2581	2586	2591
	Unit 6	2429	2434	2439	2443	2448
	Unit 7	2019	2023	2027	2031	2036
Dahanu	Unit-1 & -2	2308	2313	2317	2322	2327
Uran		2009	2013	2017	2021	2025

It is suggested that the norms for the station heat rate for existing generating Unit/Stations which have been commissioned after the effectiveness of MERC Tariff Regulations 2005, may be considered based on the norm specified by CERC, in its Tariff

Regulations, 2009. As regards the station heat rate norm for 210/250 MW series, CERC, in its Explanatory Memorandum to the draft Tariff Regulations, 2009 had stipulated as under:

> *"… **Further most of the NTPC 210 MW units are older units and would be approaching their useful life and would be due for R&M in next tariff period.** It may therefore, not be advisable to reduce the SHR norm for the existing 210 MW units. However, in case of new 210 MW units coming up on or after 1.4.2009, it should be possible to achieve better heat rates due to improvement in pressure and temperature parameters. **As such, for such new 210 MW units we intend to keep the station heat rate norm as 2450 kCal/kWh." (emphasis added)***

Further, CERC, in its Statement of Reasons to Tariff Regulations, 2009 has stipulated as under:

> *"As such, we are fixing a SHR norm of 2425 kCal/kWh (instead of 2400 kCal/kWh as proposed in draft) for the existing 500 MW units and passing on the benefit of efficiency gain to the beneficiaries. **In respect of 200/210/250 MW sets, which are relatively old and near completion of their useful life, the performance level is expected to be lower due to R&M activities, a point made by the NTPC. As such, in respect of 200/210/250 MW sets we are retaining the norms as 2500 kCal/kWh**." **(emphasis added)***

For existing generating stations/Units, which have been commissioned after the effectiveness of MERC Tariff Regulations, 2005 or expected to be commissioned before the effectiveness of MERC MYT Regulations, it is suggested that the station heat rate norm for 200/210/250 MW may be considered as 2450 kcal/kWh.

As discussed in previous paragraphs, for such Units/Stations which have not been able to achieve the performance targets specified by the Commission, the norms may be specified on the basis of CPRI recommendation. Accordingly, the station heat rate for MSPGCL and TPC-G generating stations are proposed to be considered for the next Control Period in accordance with the CPRI study. CPRI, in its report has given the heat rate trajectory till FY 2014-15. The heat rate for FY 2015-16 has been arrived by applying an annual degradation recommended in CPRI Report on the heat rate value for FY 2014-15:

kCal/kWh

Year	Koradi	Khaperkheda	Chandrapur	Nasik	Bhusawal	Paras	Parli
FY 2010-11	2965	2560	2617	2722	2734	3186	2745
FY 2011-12	2975	2568	2626	2731	2742	3199	2753
FY 2012-13	2985	2575	2635	2740	2751	3212	2762
FY 2013-14	2873	2424	2539	2664	2671	3225	2679
FY 2014-15	2881	2429	2544	2670	2677	3237	2684
FY 2015-16	2889	2433	2549	2677	2683	3250	2690

Year	Unit-5 of TPC-G
FY 2010-11	2577
FY 2011-12	2575
FY 2012-13	2583
FY 2013-14	2591
FY 2014-15	2573
FY 2015-16	2581

4.1.8.2 Auxiliary Consumption

The existing definition of auxiliary consumption specified in the MERC Tariff Regulations is as under:

> *"Auxiliary Consumption" in relation to a period, means the quantum of energy consumed by auxiliary equipment of the generating station and shall be expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station:*
>
> *and, for the purpose of these Regulations, auxiliary consumption for a thermal generating station shall include transformer losses within the generating station;"*

It is suggested that same definition of auxiliary consumption may be continued, with a slight modification. To give more clarity for calculation of auxiliary consumption, it is suggested that supply to station colony should be excluded, while computing auxiliary consumption. Suggested modification in definition of auxiliary consumption is as under:

> ***"And, for the purpose of these Regulations, station colony consumption should not be included as part of the auxiliary consumption for the generating station."***

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 past performance of the generating stations in the State of Maharashtra has been compared with the performance of generating stations in other 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						Approved				
				2004-05	2005-06	2006-07	2007-08	Average (04-08)	2008-09*	2004-05	2005-06	2006-07	2007-08	2008-09
		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
TPC-G	Trombay	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
	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
MSPGCL	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.

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

The auxiliary consumption of DTPS has been compared 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.

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 carried out by CPRI, which has been discussed subsequently.

As regards the norms for auxiliary consumption, Generating Companies have suggested to consider the highest auxiliary consumption in the five year period, i.e., FY 2004-05 to FY 2008-09, which will give them comfort for maintaining the auxiliary consumption. It is suggested that the norms for the auxiliary consumption for existing generating stations that have been performing better than the norms may be considered based on the norm specified by CERC, in its Tariff Regulations, 2009, as compiled below:

(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.

The auxiliary consumption for FGD plant shall be approved 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.

As discussed in previous paragraphs, for such stations where the stations which have not been able to achieve the performance targets specified by the Commission, the norms may be specified on the basis of CPRI recommendation. However, it is observed that the Auxiliary Consumption norm suggested by CPRI for FY 2008-09 for some of the stations is substantially higher than the actual Auxiliary Consumption and this issue has already been dealt by the Commission in its Order dated March 5, 2010 in Case No. 16 of 2008 as under:

> *"As for allowing the fuel costs, the Commission considers the gross generation and for estimating the revenue from sale of power, the Commission considers the net energy supplied from the stations, it will be more appropriate to consider the actual auxiliary consumption reported by MSPGCL based on energy export into grid. Therefore, for FY 2008-09 and FY 2009-10, the Commission approves the Auxiliary Consumption norm based on actual auxiliary consumption for FY 2008-09."*

CPRI, in its Report, has also recommended the trajectory for year-wise reduction in Auxiliary Consumption from FY 2009-10 onwards. The recommendations made by CPRI in its Report were based on short term, medium term and long term measures to be implemented by MSPGCL including capital investments. As the measures suggested by CPRI have not been implemented in FY 2009-10, it will not be appropriate to consider the auxiliary consumption reduction trajectory for FY 2009-10 and hence, it is suggested that the auxiliary consumption for FY 2009-10 may be considered equivalent to actual auxiliary consumption achieved during FY 2008-09, which will also act as base auxiliary consumption for approving the auxiliary consumption trajectory for the next Control Period. The year-wise trajectory of auxiliary consumption for the next Control Period may be approved based on year-wise percentage reductions recommended by CPRI in its Report from the base value of auxiliary consumption for FY 2009-10. Accordingly, the auxiliary consumption for MSPGCL generating stations proposed to be considered for the next Control Period are as under:

Plants	Auxiliary Consumption					
	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2013-14	FY 2014-15
Koradi	10.74%	10.65%	10.55%	10.40%	10.21%	10.00%
Paras	12.18%	11.79%	11.33%	10.74%	10.01%	9.16%
Bhusawal	10.74%	10.54%	10.30%	9.91%	9.47%	9.00%
Nashik	9.74%	9.56%	9.27%	8.93%	8.42%	7.90%
Parli	10.93%	10.57%	10.16%	9.66%	9.12%	8.49%
Khaperkheda	9.17%	9.08%	8.98%	8.81%	8.63%	8.41%
Chandrapur	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%

4.1.8.3 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 case of lignite based generating stations.

As discussed earlier, benchmarking has been considered 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 utilise multiple fuels, whereas most of the other generating stations in the State of Maharashtra and other States are not designed to utilise 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, RInfra-G's Secondary Fuel Oil consumption has been compared 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.

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).

As regards the norms for secondary fuel oil consumption for the existing generating stations, which have been commissioned or expected to be commissioned before the effectiveness of MERC MYT Regulations, it is suggested that the same may be considered based on the norm specified by CERC, in its Tariff Regulations, 2009, as stipulated below:

(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

As discussed in previous paragraphs, for such stations which have not been able to achieve the performance targets as specified by the Commission, the norms may be specified on the basis of CPRI recommendation.

In its Report, CPRI has made the following suggestions regarding Secondary Fuel Oil Consumption:

i. "*Koradi Units 1-4 have boiler furnace and APH related problems. Until these are attended, a SOC of 4 ml/kWh can be considered. After the APH and boiler related problems are attended the SOC can be restored to 2 ml/kWh.*

ii. *For Nasik units SOC of 3 ml/kWh can be considered until the boiler related problems are attended. Subsequently, the SOC can be restored to 2 ml/kWh.*

iii. *Bhusawal, Paras can achieve the SOC of 2 ml/kWh.*

iv. *Parli units can achieve the SOC of 2 ml/kWh if the mill related problems are attended.*

Units of 210 MW and above can achieve the targets of SOC with focused attention to monsoon management plans, coal quality improvements, leakage control and operational optimization."

As may be observed from the above recommendations of CPRI, the Units of the generating stations are capable of achieving the normative secondary fuel oil consumption (SFC) of 2 ml/kWh and the high secondary fuel oil consumption is on account of various problems as listed by CPRI. CPRI, in its Report, has given recommendations for secondary fuel oil consumption that can be achieved considering the current plant conditions and SFC that can be achieved with improvements.

Considering the CPRI recommendations for achievable SFC with improvements it is suggested that the normative secondary fuel oil consumption for MSPGCL stations may be specified as 2ml/kWh.

4.1.8.4 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.

Further, it may be noted that RInfra-G reports transit loss on imported coal also, 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.

During the expert consultation process, Generating Companies submitted that CERC Regulations do not specifically exclude imported coal for allowing transit loss and submitted that zero transit loss as reported by other Generating Companies on imported coal could be on account of accounting system (wherein the losses are included in consumption) or contractual arrangement (delivery basis). Procurement of coal on delivery basis amounts to inland sale and would attract additional taxes. Thus contracting on delivery basis is not in the interest of consumers. It was further suggested that study of the advantages and disadvantages of contracting imported coal on delivery basis should be done and if such analysis indicate a lower cost of procurement, all generating companies shall follow the same.

The concept of allowing transit loss separately is applicable particularly for procurement of domestic coal from Coal India Limited (CIL) as the CIL measures and charges for quantity of coal at the loading point. However, if the coal is being procured on delivery basis, no transit losses shall be applicable. Accordingly, it is suggested that in case of procurement of coal on delivery basis, no transit loss may be allowed and in cases where the coal is procured on the basis of measurement at loading point, normative transit loss may be allowed.

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:

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 coal including washed coal and imported coal.

4.1.9 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 are much higher as compared to large unit size thermal stations. The O&M expenses for thermal stations also depend upon vintage of stations and hence the O&M expenses of older vintage stations are higher as compared to new stations.

It is felt 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.

As regards insurance expenses, the Commission has been considering the insurance cost as a part of O&M expenses. Accordingly, it is suggested that O&M expenses may be defined in the MYT Regulations for generation as under:

> *'operation and maintenance expenses' or 'O&M expenses' means the expenditure incurred on operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, repairs, spares, consumables, insurance, and overheads.*

As regards the O&M expenses, Generating Companies submitted that the base year for the Second Control period should be the Audited Accounts of FY 2009-10 and the

Commission should determine employee cost in accordance with the structure followed by organizations like NTPC or PSERC. Some of the Generating Companies submitted that the norms for O&M expenses should be fixed in accordance with CERC Tariff Regulations, 2009 which is based on statistical data of all the plants operational in the country. As regards the consideration of O&M expenses, it may be noted that CERC, in its Tariff Regulations, 2009 has specified the normative O&M expenses after considering the average normalised O&M expenses for three years, i.e., FY 2004-05 to FY 2006-07 and escalating the same @5.17% every year to compute the normative O&M expenses for FY 2009-10. Moreover, CERC has considered 45% increase in employee cost to arrive at normative O&M expenses for FY 2009-10 with pay revision impact.

In the draft Approach Paper, it was proposed to consider a similar methodology to consider the past performance of the individual stations for specifying the O&M expense norms. Hence, the approach suggested in the draft Approach Paper may be continued, however, as against the proposal to consider average of five years, the same has been revised to three years.

Therefore, 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 three (3) 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, 2008, which will be escalated based on the escalation factor, to arrive at O&M expenses for the base year commencing April 1, 2011.
c) The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above for FY 2011-12, at the escalation factor to arrive at permissible O&M expenses for each year of the Control Period.

For new stations commissioned and which have not achieved the operation of three years from the date of commissioning 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 arrive at permissible O&M expenses for each year of the Control Period.

As regards the O&M expenses for new generating stations to be commissioned after the effectiveness of the MYT Regulations, it is suggested that the O&M expenses for first year of the Second Control Period may be specified based on norms in the existing MERC Tariff Regulations, escalated based on escalation factors to arrive at permissible O&M expenses for each year of the first Control Period as follows:

i. O&M Expenses for 210/250 MW Unit

Particulars	FY 12	FY 13	FY 14	FY 15	FY 16
O&M Expenses for 210/250 MW (Rs. Lakh/MW)					
Escalation rate	5.72%	5.72%	5.72%	5.72%	5.72%
O&M Expenses (Rs. Lakh/MW)	14.81	15.66	16.55	17.50	18.50

ii. O&M Expenses for 500 MW and above Unit

Particulars	FY 12	FY 13	FY 14	FY 15	FY 16
O&M Expenses for 500 MW and above Unit (Rs. Lakh/MW)	13.32	14.08	14.89	15.74	16.64

Note:

For the generating Units/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

iii. O&M Expenses for lignite based generating Units/Stations:

Particulars	FY 12	FY 13	FY 14	FY 15	FY 16
O&M Expenses (Rs. Lakh/MW)	14.81	15.66	16.55	17.50	18.50

iv. O&M Expenses for Gas Turbine/Combined Cycle generating Unit/Stations

Particulars	Gas Turbine/Combined Cycle Generating Stations	Small Gas Turbine Generating Stations (less than 50 MW unit size)

	With warranty spares for 10 years	Without warranty Spares	Without warranty Spares
FY 2011-12	7.41	11.10	13.47
FY 2012-13	7.83	11.74	14.24
FY 2013-14	8.28	12.41	15.05
FY 2014-15	8.75	13.12	15.91
FY 2015-16	9.25	13.87	16.83

4.1.10 Non Tariff Income

The existing MERC Tariff Regulations do not specifically specify the treatment of non tariff 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 non tariff 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 non tariff 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 non tariff income, the income corresponding to interest on investment made out of permissible Return on Equity should not be considered as non tariff income. Some of the heads, which should be considered under non tariff income for adjustment from the fixed (capacity) charges, are as follows:

- Income from rent of land or buildings
- Income from sale of scrap
- Income from statutory investments
- Income from sale of Ash/rejected coal
- Interest from consumers (Interest on delayed or deferred payment on bills)
- Interest on advances to suppliers/contractors
- Interest on Income tax refund
- Rental from staff quarters
- Rental from contractors
- Income from hire charges from contactors and others
- Gain on Foreign Exchange Fluctuation
- Income from advertisements, etc.

4.1.11 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.

The availability and PLF for various generating stations in the State of Maharashtra for the period from FY 2004-05 to FY 2007-08 has been analysed 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 the draft Approach Paper, it had been proposed to link the incentive mechanism with target PLF based on actual generation.

During expert consultation process, the Generating Companies submitted that the incentive should be linked to Availability and Annual Fixed Charges as stipulated by CERC, since actual generation is not controlled by the generator and depends on demand and also the position of the station in the merit order. Further, they submitted that the if a generator is available for generation, with machine, manpower and fuel, it should be allowed to recover fixed charges as well as incentive irrespective of whether the plant has actually generated or not.

As regards the suggestions made regarding linking incentive to Availability and Annual Fixed Charges, the draft Approach Paper had proposed that if incentive is provided in terms of additional Return on Equity (RoE) or Return on Capital Employed (RoCE) linked with Availability, the incentive will vary for each Generating Station based on capital cost and means of finance of the Generating Station and this approach will also conversely provide more incentive to generating stations with higher capital cost. As regards suggestions made regarding linking incentive to Availability draft Approach Paper had proposed that 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. Hence, it is suggested to not link the incentive to Availability and Annual Fixed Charges.

Some Generating Companies also submitted that PLF should be linked to scheduled generation since linking incentive to scheduled generation takes care of the impact of backing down instruction from SLDC for load management/grid security. Considering the suggestions made by stakeholders to condier the backing down instruction, it is proposed to link the incentive to actual generation, however, in case of any backing down instruction from MSLDC, the same should be considered as deemed generation for computing the incentive so that the generation loss due to backing down instructions is also considered and the Generating Company gets incentive, if the station is available but has not operated due to backing down instruction.

However, as 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

*Note: Actual generation should also consider the generation loss on account of backing down instruction from MSLDC.

4.1.12 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.

4.1.13 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.

4.1.14 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,

$$A = \frac{10 \times (SFC_n)\ (P_{om}) - (P_{os})}{(100 - AC_n)}$$

$$B = \frac{10}{(100 - AC_n)} \left[\{(SHR_n)\ (P_{cm}/K_{cm}) - (P_{cs}/K_{cs})\} - (SFC_n)\ \{(k_{om} x P_{cm}/K_{cm}) - (k_{os} x P_{cs}/K_{cs})\} \right]$$

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, it is proposed 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.

During the stake-holder consultation, Generating Companies requested to fix the quantum of Design Energy for hydro generating stations in the MYT Tariff Regulations. As regards the request to specify the design energy for hydro generating stations, it is felt that the same may be specified on case to case basis while processing the Petitions to be filed for determination of multi year tariff.

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.
It is suggested that the Annual Fixed Cost (AFC) for a Hydro Generating Station shall comprise of the following elements:

- Depreciation
- O&M Expenses
- Return on Capital Employed
- Interest on Working Capital

  Less:
- Less non tariff income

4.2.3 Norms of Operation

<u>Normative Capacity Index for Recovery of Annual fixed Charges</u>

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%

During the stakeholder consultation, Generating Companies submitted that the Approach Paper should also specify the operating norms of the pumped storage stations. As regards the operating norms, the Commission in its Order in Case No. 94 of 2007 has stipulated as under:

> *"Considering the variation in operating performance parameters of existing pumped storage stations, the Commission is of the view that it will not be proper to specify uniform norms of operation for all the pumped storage stations. Further, as submitted by MSPGCL, most of the upcoming Pumped Storage Stations are currently in planning phase. Accordingly, the Commission is of the view that it will take time to have sufficient operational data from various pumped storage stations to evolve uniform norms for pumped storage stations. Considering these aspects, the Commission is of the view that any relaxed norm for any pumped storage station, vis-à-vis normal hydro generation stations, needs to be approved on*

case to case basis. The Commission will approve the norms of new stations while determining the tariff based on Petition filed for determination of tariff upon completion of the Project..."

Accordingly, it is proposed that operating norms for pumped storage stations may be specified on case to case basis while determining the tariff based on Petition filed for determination of tariff for such station.

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 three 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 three (3) 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, 2008, which will be escalated based on the escalation factor to arrive at O&M expenses for the base year commencing April 1, 2011.

In case of the hydro generating stations, which have not been in commercial operation for a period of three 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 for the base year commencing April 1, 2011.

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 2011-12, at the escalation factor 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.

4.2.6 Reactive Energy Charges

During the expert consultation, Generating Companies submitted that reactive energy charges have not been mentioned in the draft Approach Paper, which may be beneficial for condenser mode operations of hydro stations and requested that such efforts for grid stability should be incentivized. As regards the compensation for reactive energy injected into the grid, the Commission in its Order dated March 5, 2010 in Case No. 16 of 2008 had stipulated as under:

> *"In this regard, it is clarified that there is no expenditure that is incurred by MSPGCL for injection of reactive energy that is not being compensated, since all the expenses prudently incurred by MSPGCL are recovered through the tariffs, irrespective of whether or not MSPGCL is generating active energy at the time of injecting reactive energy. Further, such additional compensation for reactive energy injection by the generator has not been given even by the CERC in the recently notified Tariff Regulations."*

Accordingly, it is suggested that no separate compensation may be allowed to generation companies for injecting reactive energy into the grid.

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 'function-wise' 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

<u>*National Electricity Policy*</u>

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)***

<u>*Tariff Policy*</u>

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. <u>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</u>." ... (<u>Emphasis added</u>)

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 (Based on Approach Paper on Transmission Pricing published by CERC)

Central Electricity Regulatory Commission (CERC) has published an Approach Paper in May 2009 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 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

Marginal Participation (MP) Method

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 Salient features of draft CERC (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010

Subsequent to the publishing of the Approach Paper and pursuant to stakeholder consultation on sharing of Transmission Charges and Losses, CERC has published draft Regulations on February 9, 2010 incorporating the comments received on the Approach Paper. CERC, after due consideration of the alternative methodologies for allocation of transmission charges and the comments received from various stakeholders has considered implementation of the Point of Connection (PoC) methodology based on a hybrid method, which brings together the strengths of both the Marginal Participation and the Average Participation Method discussed in the Approach Paper. Under this framework, any generator node is required to pay a single charge based on its location in the grid to gain access to any demand customer located anywhere in the country. Similarly, any demand node will also be required to pay just one charge and get access to any generator in the grid. This is based on load flow studies conducted for each node, one at a time. The same principle holds for transmission losses that a generator node or demand node has to bear. Here the usage of term 'node' refers to a point on the grid, which pertains to the point of injection by a generator or a point of drawal by the demand customer.

The salient features of the draft Regulations are:

a. All users of ISTS network (called as DICs or Designated ISTS Customers) would have to pay charges and bear loss compensation depending on where they are placed in the national network. Such charges will be called PoC (Point of Connection) Charges. For example, for generators located close to a load centre, the charges would be relatively less, and vice-versa. Similarly, demand customers located near generation hubs would have relatively lesser charges or losses allocated to them.

b. The PoC charges will be a hybrid of charges determined through the Marginal Participation and the Average Participation Methods of determination of Transmission Charges.

c. The Implementing Agency (IA) (agency designated by the CERC to undertake the estimation of the transmission charges and transmission losses at the various nodes/zones) shall collect the basic network data pertaining to the network elements and the generation and load at the various network nodes from all concerned entities including DICs, generating stations/companies, transmission licensees, distribution licensees, NLDC, RLDCs, SLDCs, RPCs.

d. The IA will run the PoC methodology to allocate transmission charges and losses.

e. No differentiation in rates is proposed between the long-term, medium-term and short-term users of the transmission system. However, these would be accorded in decreasing order of priority in event of system constraints.

f. No transmission charges for the use of ISTS network shall be charged to solar based generation. This shall be applicable for the useful life of the projects commissioned in next three years.

g. The RPCs shall maintain accounts of the ISTS charges to be collected from each DIC of the ISTS based on information provided by the CTU. The bills would be raised based on the final accounts certified by the RPCs.

h. In the case of transactions through the Power Exchange, the demand DIC shall pay the zonal PoC charges applicable to the zone where such demand customer is physically located and the generator DIC shall pay the transmission charges as per the PoC transmission charge applicable to the zone where such a generator is located.

i. The constituents and service providers on the ISTS shall enter into new transmission services agreement or modify the existing BPTAs to incorporate the new tariff and related conditions. Such agreement shall govern the provision of transmission services and charging for the same shall be called the transmission Connection and Use of Service Agreement (CUSA).

j. The CTU shall be responsible for raising the transmission bills for the entire ISTS irrespective of ownership, collection and disbursement of transmission charges to all other transmission licensees, whose assets have been used for the purpose of inter-State transmission of power. For such services, the CTU shall be entitled to levy and recover a charge from DICs as approved by the Commission.

k. For implementation, in the first two years, it is proposed that the Commission will apply transmission charges and losses based on a combination of PoC methodology and a Postage Stamp methodology in a ratio of 50:50. The Commission may consider increasing the locational signal by reducing the proportion of the postage stamp component over time.

5.2.6 Requirements & feasibility to introduce MP approach at State level

The Marginal Pricing method as proposed in the CERC Approach Paper and subsequently in the draft Regulations 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 SLDC/STU (or any other agency designated by the Commission 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**

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.
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	The transmission charges in Rs/MW for each season at each node to be

Requirements of MP method	CERC approach	Required Intra-State approach
	determined based on the load flow studies	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, it would be 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. 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

It is proposed to derive the O&M norms for the transmission licensees in the State of Maharashtra based on relationship between the drivers of O&M expenses and parameters such as line length in circuit km and number of bays. 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, following four step approach has been adopted 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, a comparison of various technical/physical parameters of selected Transmission Utilities has been provided, 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)

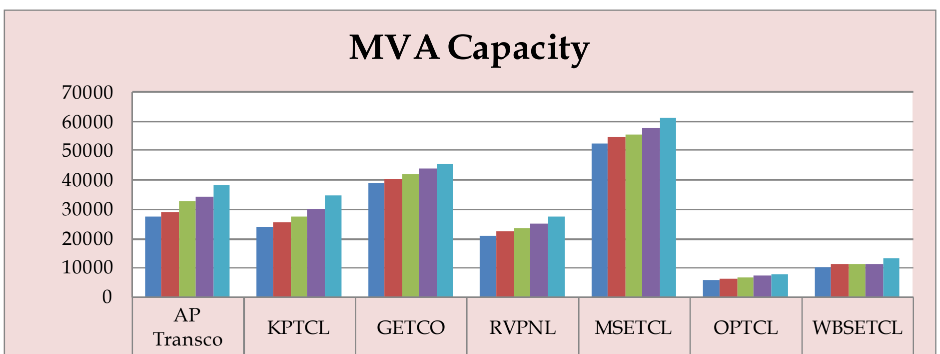
c. Number of substations/Number of bays

d. Operating Voltage levels

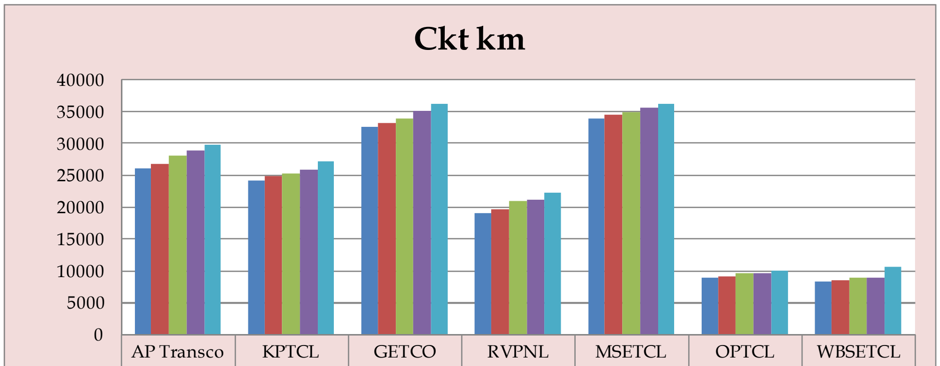
e. Energy handled (MU)

f. Average/Peak demand catered by the transmission system (MW)

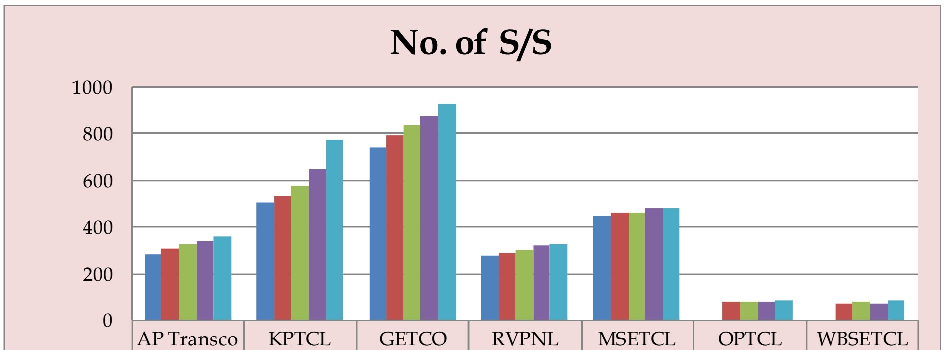
The following graphs provide a snapshot of the growth of Transmission Utilities in terms of their grid substation capacity (MVA), transmission line length (ckt-km) and number of substations (no.) during the period from FY 2003-04 to FY 2007-08. The transmission utilities considered for this comparative 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.

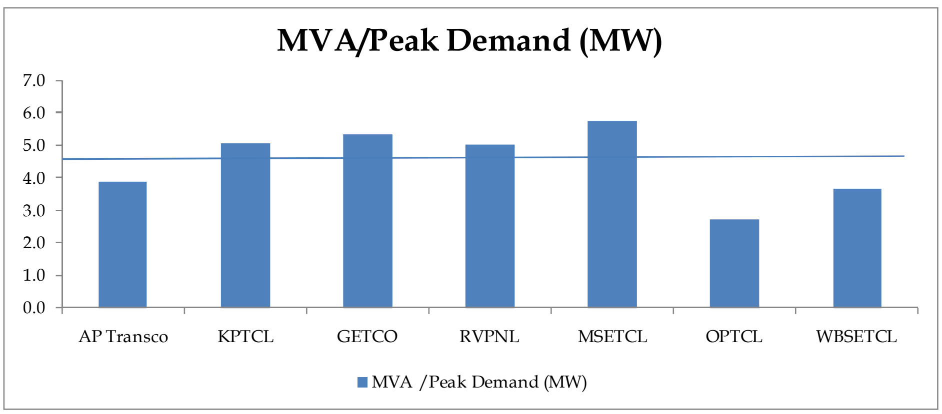
In order to compare the technical parameters of selected Transmission Utilities, certain ratios have been derived for various physical parameters as outlined below:

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)**

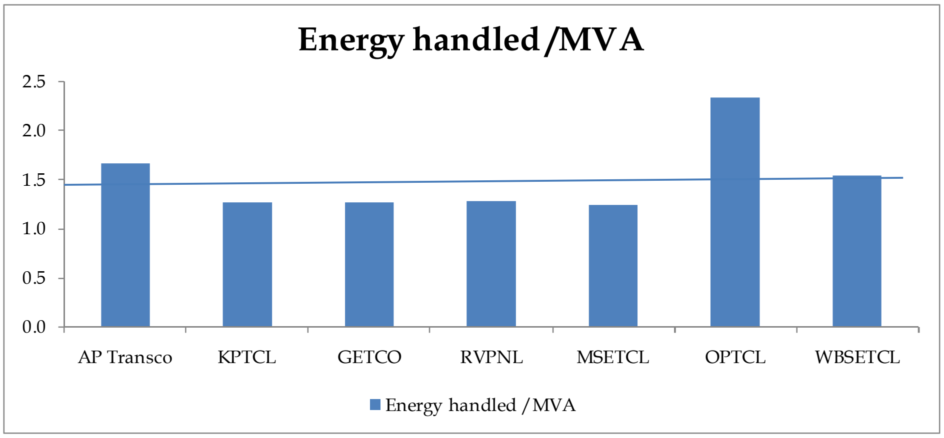


	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
MVA /Peak Demand (MW)	3.9	5.1	5.3	5.0	5.8	2.7	3.6

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**

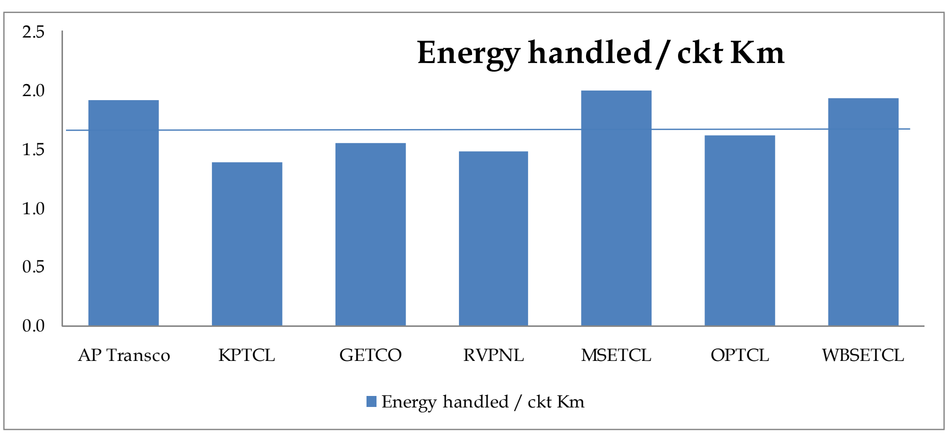
Another important physical parameter considered for comparison of configuration of network of Transmission Utilities is the energy handled or energy transmitted through the network. The ratio of Energy units handled (MU) to Grid Substation Capacity (MVA) and ratio of Energy units handled (MU) to transmission 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.

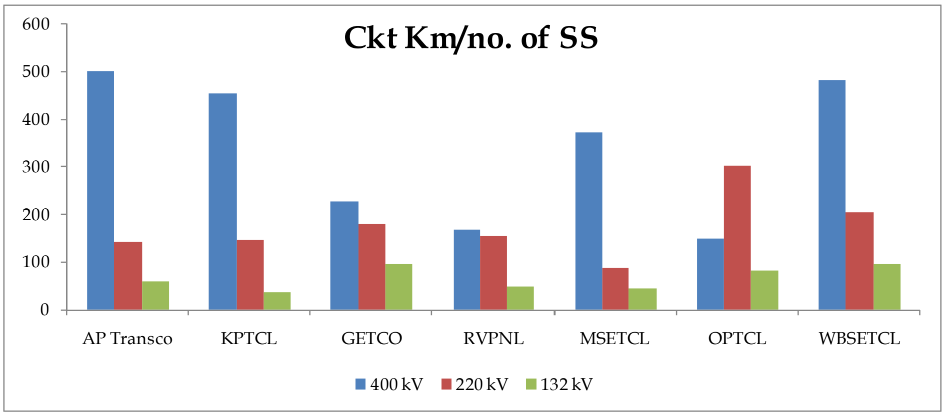
3. Energy units handled (MU) / transmission line length (ckt km)



	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)**

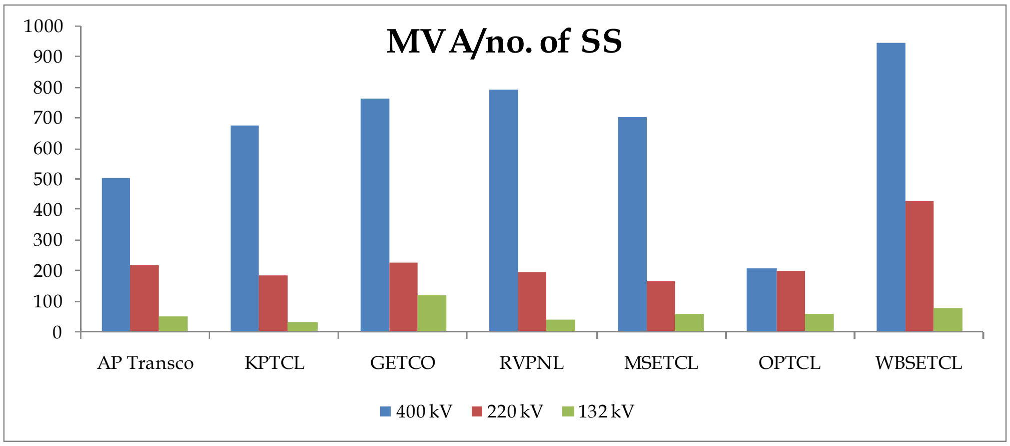


	AP Transco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL	WBSETCL
400 kV	502.97	454.66	227.37	167.49	373.37	147.33	482.75
220 kV	143.88	145.73	180.60	154.21	86.33	302.19	204.92
132 kV	57.83	36.63	94.78	46.98	45.69	81.32	95.65

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. <u>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.

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. However, the configuration in terms of MVA capacity and number of substations at higher operating voltage is somewhat uneven in nature.

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.

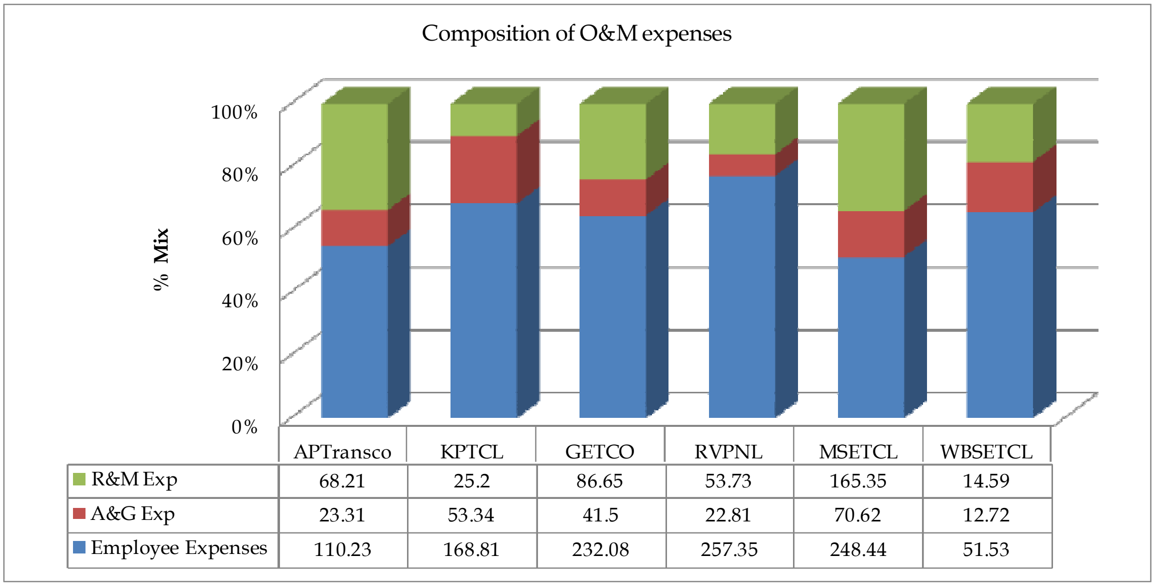
5.4.2.2.3 *Comparison of O&M Cost Components and cost structure across transmission Utilities*

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.



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.

Further, comparison of various cost components of O&M expense across transmission utilities on **Per Unit basis** has been derived, which is presented below. In addition, the variation over the two year period for each utility over FY07 and FY08 is summarised 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.

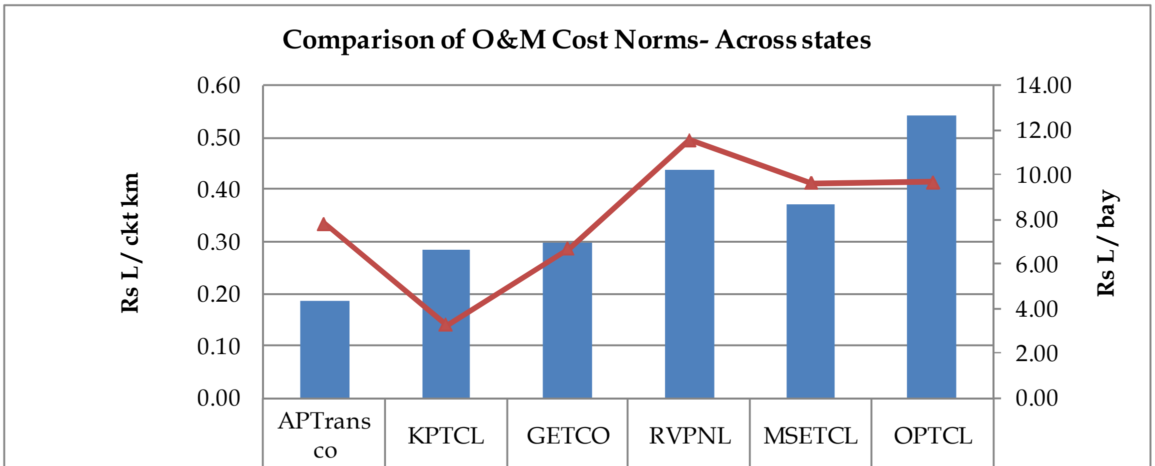
Another important point which is noted from above comparison that while energy units handled by transmission system is one of the important performance parameter, the variation in terms of per unit is significant depending on energy units handled. Thus, in case O&M norms are specified in terms of 'Per 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. 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:



	APTransco	KPTCL	GETCO	RVPNL	MSETCL	OPTCL
Rs L / Ckt km	0.19	0.29	0.30	0.44	0.37	0.54
Rs L / bay	7.80	3.30	6.70	11.55	9.65	9.66

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) 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). While the transmission licences have also been issued in case of M/s Jaigad Power Transco Ltd and M/s Adani Power Maharashtra Ltd, the transmission assets of these transmission licensees are yet to be built and yet to be operational. 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.

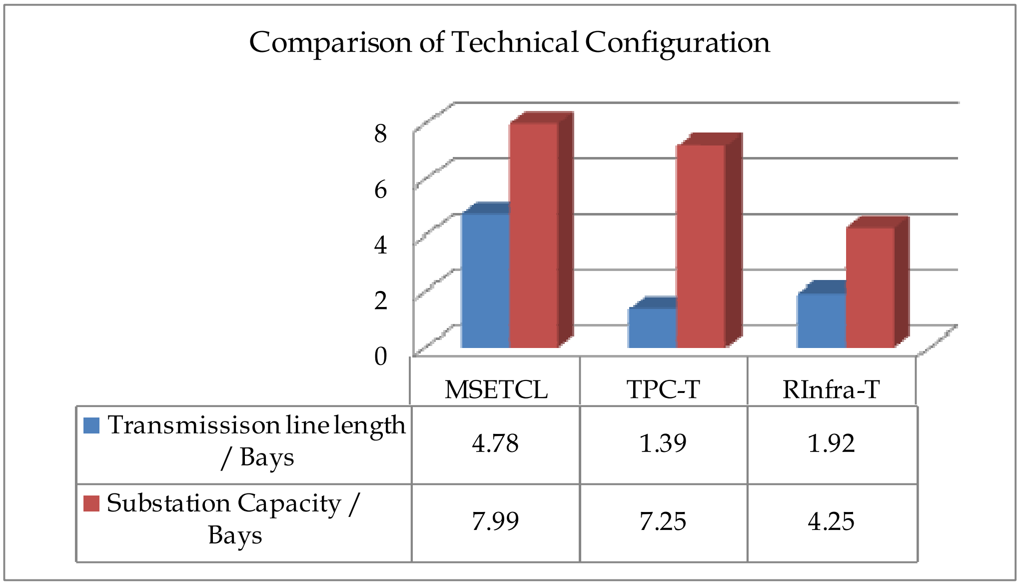
Particulars	Units	MSETCL	TPC-T	RInfra-T
Transmission line length	ckt Km	36409	1191	480.5
MVA capacity	MVA	62459	6644	1100
No of substations	no.	484	16	3
No of bays	no.	8111	834	251
Transmission line length / Bay	ckt Km/bay	4.49	1.43	1.91
Substation Capacity / Bay	MVA/bay	7.70	7.97	4.38

For the purpose of analysis and for deriving O&M norms, the 'Bay' has been considered as a set of accessories that are required to connect an electrical equipment such as Transmission line, Bus Section Breakers, Potential Transformers, Power Transformers, Capacitors and Transfer Breaker and the feeders emanating from the bus. Further, the Bays considered here includes only the ones of a Transmission substation and thus excludes any bays of the Generating Station switchyard whose maintenance is usually the responsibility of the Generating Company.

In the above table, 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 RInfra-T.

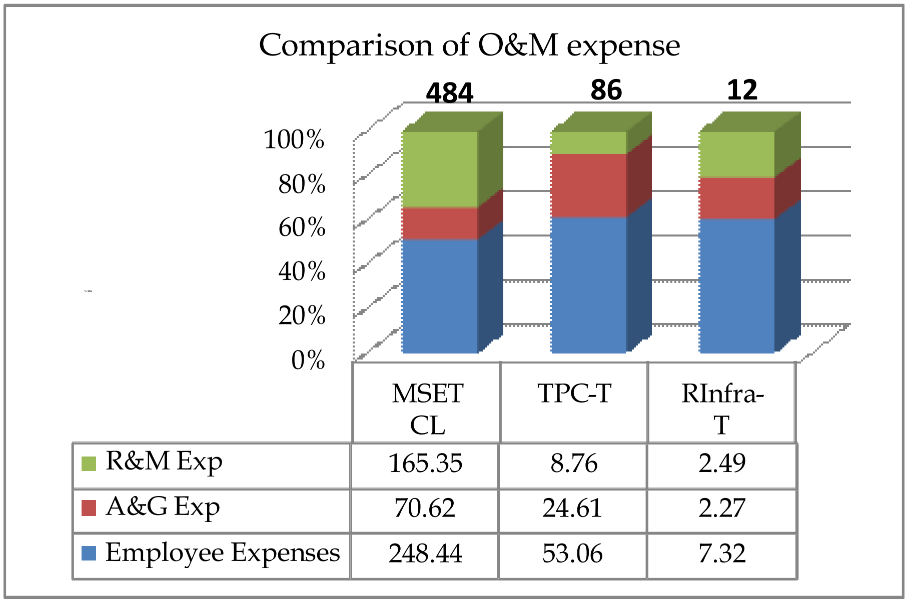
MSETCL	2006-07	2007-08	2008-09	Average
ckt km/no of bays	5.33	4.50	4.49	4.78
MVA/no of bays	8.64	7.64	7.70	7.99
TPC-T				
ckt km/no of bays	1.47	1.26	1.43	1.39
MVA/no of bays	5.72	8.06	7.97	7.25
RInfra-T				
ckt km/no of bays	1.92	1.91	1.91	1.92
MVA/no of bays	3.98	4.38	4.38	4.25

The average of such ratios for the past 3 years (FY 2006-07 to FY 2008-09) of each Utility has been computed in the Table above.



The above comparison shows that there exists significant difference in the network configuration of the three Utilities. In this context, it would also be worthwhile to note that the transmission network of TPC-T also includes underground transmission lines of 220 kV and 110 kV voltage levels. Based on submissions of TPC-T to MERC as part of their APR Petition for FY 2008-09, 86 Ckt km out of the total transmission line length of 1053 Ckt Km of TPC-T, pertains to underground transmission cables.

The chart below compares the composition of O&M expenses of MSETCL, TPC-T and RInfra-T for FY 2007-08.



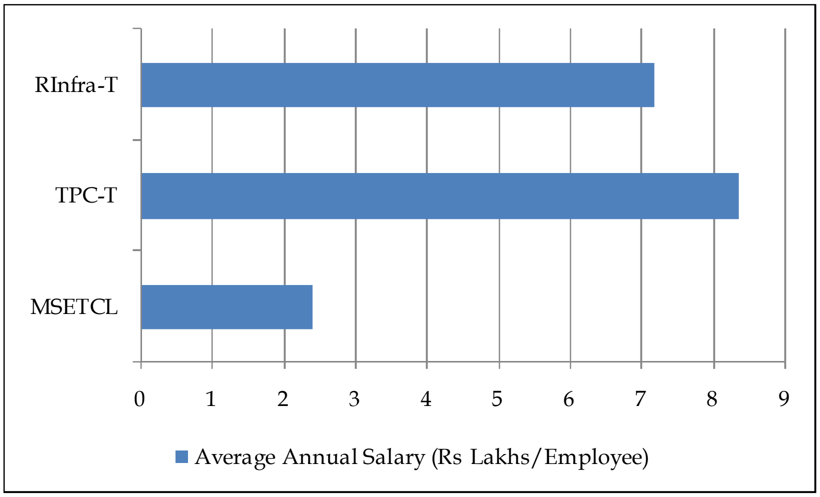
Considering the share of employee expense, which ranges from around 50% to 60% of the total O&M expense of MSETCL, TPC-T and RInfra-T, it is worthwhile to compare the Utilities in terms of their employee configuration as well. The detailed break up of number of employees of MSETCL, TPC-T and RInfra-T as on FY 2007-08 ending, as submitted by the respective Utilities as part of the APR Petition for FY 2008-09, is tabulated below.

	MSETCL	**TPC-T**	**RInfra-T**
Technical	8382	462	101
Administrative	1167	52	1
Accounts and finance	676	32	0
Others	133	122	0
Total Employees	10358	668	102

Particulars	**MSETCL**	**TPC-T**	**RInfra-T**
No. of Employees per S/S	21	42	34
No. of Employees per bays	1	1	0.4
MVA capacity per No. of Employees	6	10	11

A comparison of the average salary of employees of the Utilities was also made to bring out the difference or similarity among the Utilities in this aspect.

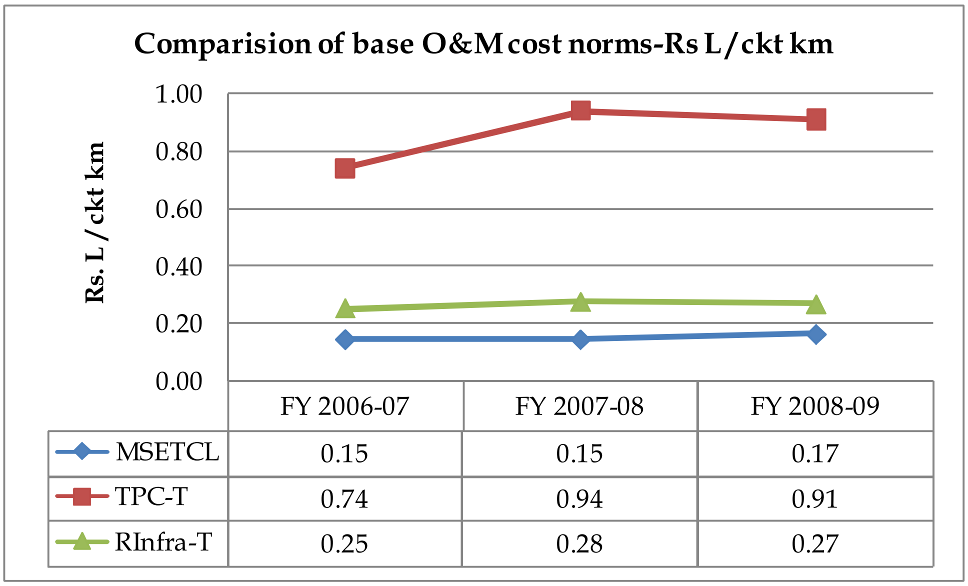
The chart below compares the Average Annual Salary of employees in Rs lakh for FY 2007-08.



From the above, it can be inferred that O&M cost structure and organisational arrangement for O&M of transmission systems of MSETCL, TPC-T and RInfra-T are strictly not comparable to each other in terms of their employee and technical configuration.

In order to compare the relation of O&M expense as a whole with the physical network configuration of various Utilities, ratios such as O&M expense per ckt Km and O&M expense per number of bays have been derived and is compared across various Utilities.

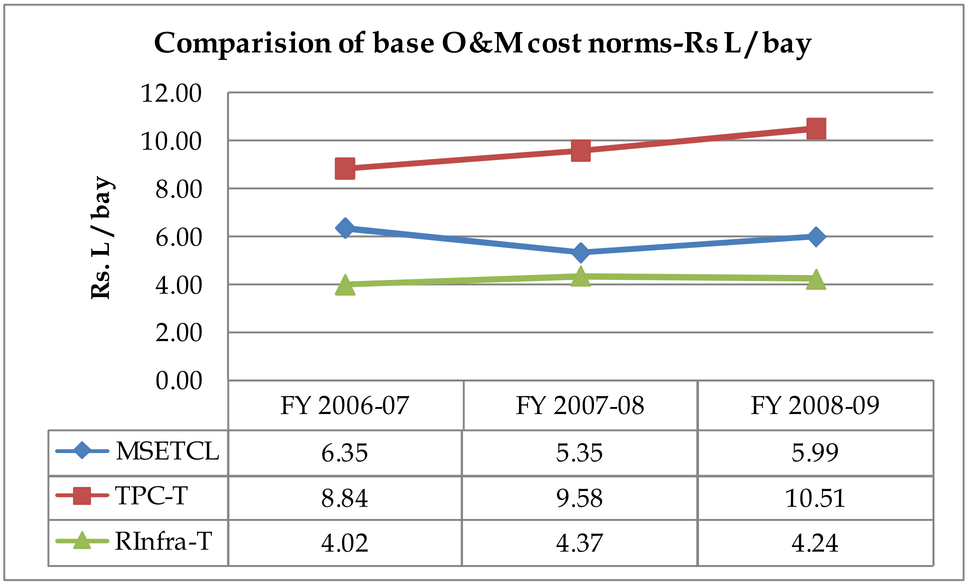
The chart below depicts the base O&M expense norms[1] based on Rs Lakh/ckt km and Rs lakh /bay for the Utilities. For comparison purposes, average of base O&M expense norms for three years (FY 2006-07 to FY 2008-09) for each Utility have been considered.



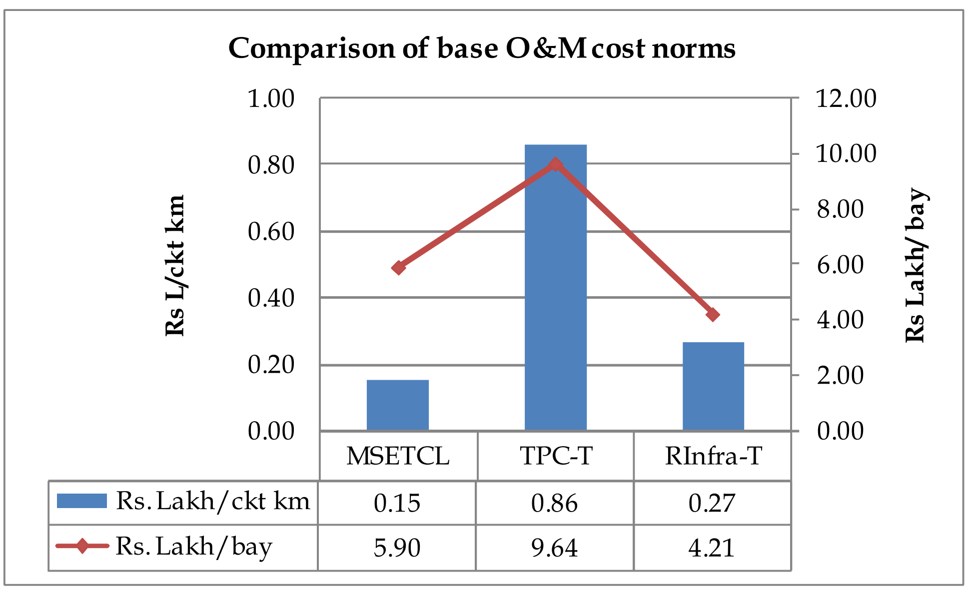
	FY 2006-07	FY 2007-08	FY 2008-09
MSETCL	0.15	0.15	0.17
TPC-T	0.74	0.94	0.91
RInfra-T	0.25	0.28	0.27

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:

[1] Base O&M norms here refers to norms derived without voltage wise classification of asset base



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.

Comparison of O&M expenses of the Intra-State Transmission licensees in Maharashtra with that of CTU (PGCIL)/CERC norms

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, separate norms have to be derived for each transmission licensee to address characteristic features and historical developments of transmission network and operating structure of these transmission licensees. Further, considering the fact that R&M expense, which constitutes 15% to 30% of O&M cost varies significantly from one voltage level to other, voltage-wise O&M norms have to be derived for all Utilities. Hence, it is proposed to derive O&M norms for the following set of voltage classes:

1. HVDC,
2. 765 kV
3. 400 kV
4. Above 66 kV but lower than 400 kV (220 kV, 132 kV, 110 kV, 100 kV)
5. 66 kV and lower

However, in case of TPC-T and RInfra-T, due to their limited voltage levels of operation, O&M norms are being proposed only for the last two voltage levels appearing in the above list, i.e., (a) Above 66 kV but lower than 400 kV and (b) 66 kV and lower.

Another factor to be considered while deriving O&M norms for a Transmission Licensee is the spread and nature of the transmission asset base. Thus, it becomes necessary to derive the norms in terms of number of bays (representing Substation Asset expenses) and in terms of length of transmission line (representing line expenses). Therefore, in addition to the voltage level segregation, norms have been proposed in terms of 'per ckt km basis' and 'per bay basis'.

Further, as regards MSETCL, pay revision would have a significant bearing on the O&M expenses of the Licensee in the subsequent years and to that extent, the norms derived from past data based on time series analysis need to be adjusted to account for such impact of pay revision. Based on submissions of MSETCL as part of APR process, it is envisaged that an impact of 30% increase may be expected in the employee expense of MSETCL on account of pay revision. In order to factor this impact, the normative employee expense of FY 2010 of MSETCL have been suitably adjusted and a 'Pay revision adjusted O&M norm' has been proposed for MSETCL for the next Control Period.

The methodology for formulation of O&M norms is elaborated as under:

a) The year-wise O&M expenses (of FY 2006-07 to FY 2008-09) has been allocated among bays and transmission line length (ckt km) in the ratio 89:11 on the basis of share of asset base comprising substation related asset base and transmission line related asset base, as submitted by transmission licensees and also based on information furnished by transmission licensees for approval of capex schemes. The allocation ratio of 89:11 for allocating O&M expense between bays and lines has been assumed uniformly for all the transmission licensees.

b) Based on the above allocation to bays and transmission lines, O&M expense per circuit-km and O&M expense per bay has been computed for each year (FY 2006-07 to FY 2008-09) by dividing the O&M expenses for lines/bays with the total line length in km/total number of bays in respective years.

c) Secondly, the O&M expenses so shared among bays and transmission lines has been further allocated voltage-wise by assigning appropriate weightage based on the asset base constituting bays and transmission lines at various voltage classes. (Approach for deriving O&M norms for HVDC and 765 kV in case of MSETCL is based on principles adopted for regional transmission network under CERC Tariff Regulations as explained in the Box: *Premise for O&M norms for MSETCL*)

d) The norm for the next Control Period for various voltage classes 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 for each transmission licensee. The average norm so derived has been escalated linked to suitable inflation indices comprising weighted average of wholesale price index (WPI) and consumer price index (CPI). In case of MSETCL, impact of hike due to pay revision has been accounted for by way of adjustment factor for FY 2009-10 apart from inflation factor. For subsequent years of the Control Period, escalation factor linked to inflation indices has been applied to derive applicable O&M norm for respective yearly periods of the next Control Period.

Premise for O&M norms for MSETCL

MSETCL is operating and maintaining +/- 500 kV, 1500 MW HVDC bipole line between Chandrapur and Padghe. This link transfers bulk power from eastern side of Maharashtra to load centre located in Western Maharashtra. For deriving the O&M expenses of this HVDC bipole line, the same is compared with that of the Rihand-Dadri HVDC line owned by PGCIL which has a similar technical specification. Akin to Chandrapur-Padghe line. Rihand-Dadri HVDC line is a bipole (+/- 500 kV) line with a transmission capacity of 1500 MW. The only variant feature of Rihand-Dadri HVDC bipole and Chandrapur-Padghe HVDC bipole is in terms of their length (1634 ckt km for Rihand-Dadri HVDC line and 1504 ckt km for Chandrapur-Padghe HVDC). CERC in it Terms and Conditions of Tariff Regulations, 2009 has specified O&M norms for Rihand-Dadri HVDC line. Since Chandrapur-Padghe has a similar configuration with the Rihand-Dadri line, a similar O&M norm as specified by CERC is considered here for the former with prorata adjustment to factor in the variation in length of the HVDC transmission lines.

MSETCL plans to construct a 765 kV AC transmission corridor from Nagpur to Aurangabad, which is proposed to be commissioned in FY 2013-14. Since no past data on the O&M expense for such voltage level in Maharashtra is available, the ratio between 400 kV and 765 kV O&M norms specified by CERC is considered to extrapolate the norms for 765 kV transmission networks of MSETCL for the next control period.

Accordingly, the O&M norm proposed for MSETCL, TPC-T, and RInfra-T for the next Control Period is as following:

MSETCL

Item Description	Norm for O&M Cost FY 07	Norm for O&M Cost FY 08	Norm for O&M Cost FY 09	Average (FY 08-norms)	Norm for O&M Cost FY 10	Norms adjusted for Pay revision of MSETCL (FY 10)	Ist year of control period (FY 2011-12)	2nd year of control period (FY 2012-13)	3rd year of control period (FY 2013-14)	4th year of control period (FY 2014-15)	5th year of control period (FY 2015-16)
Rs Lakh/ckt km											
HVDC (Rs lakhs)							1492	1577	1667	1763	1863
765 kV							0.64	0.68	0.72	0.76	0.80
400 kV	0.30	0.30	0.34	0.31	0.35	0.41	0.46	0.48	0.51	0.54	0.57
>66kV<400 kV	0.12	0.12	0.14	0.13	0.14	0.16	0.18	0.19	0.20	0.22	0.23
66kV and less	0.07	0.07	0.08	0.08	0.08	0.10	0.11	0.12	0.12	0.13	0.14
Rs Lakh/bay											
765 kV							121.35	128.29	135.63	143.39	151.59
400 kV	60.47	55.59	62.23	59.43	65.73	77.56	86.69	91.65	96.89	102.43	108.29
>66kV<400 kV	8.76	8.06	9.02	8.61	9.53	11.24	12.56	13.28	14.04	14.85	15.69
66kV and less	1.83	1.68	1.88	1.80	1.99	2.35	2.63	2.78	2.93	3.10	3.28

TPC-T

Item Description	Norm for O&M Cost FY 07	Norm for O&M Cost FY 08	Norm for O&M Cost FY 09	Average (FY 08-norms)	Norm for O&M Cost FY 10	Ist year of control period (FY 2011-12)	2nd year of control period (FY 2012-13)	3rd year of control period (FY 2013-14)	4th year of control period (FY 2014-15)	5th year of control period (FY 2015-16)
Rs Lakh/ckt km										
400 kV						NA	NA	NA	NA	NA
>66kV<400 kV	0.74	0.90	0.97	0.87	0.97	1.08	1.14	1.21	1.28	1.35
66kV and less						NA	NA	NA	NA	NA
Rs Lakh/bay										
400 kV						NA	NA	NA	NA	NA
>66kV<400 kV	23.10	24.11	29.42	25.54	28.25	31.58	33.38	35.29	37.31	39.45
66kV and less	4.83	5.04	6.15	5.34	5.90	6.60	6.98	7.38	7.80	8.24

RInfra-T

Item Description	Norm for O&M Cost FY 07	Norm for O&M Cost FY 08	Norm for O&M Cost FY 09	Average (FY 08-norms)	Norm for O&M Cost FY 10	Ist year of control period (FY 2011-12)	2nd year of control period (FY 2012-13)	3rd year of control period (FY 2013-14)	4th year of control period (FY 2014-15)	5th year of control period (FY 2015-16)
Rs Lakh/ckt km										
400 kV						NA	NA	NA	NA	NA
>66kV<400 kV	0.25	0.28	0.27	0.27	0.29	0.33	0.35	0.37	0.39	0.41
66kV and less						NA	NA	NA	NA	NA
Rs Lakh/bay										
400 kV						NA	NA	NA	NA	NA
>66kV<400 kV	11.91	12.95	12.57	12.47	13.80	15.42	16.30	17.23	18.22	19.26
66kV and less	2.49	2.71	2.63	2.61	2.88	3.22	3.41	3.60	3.81	4.03

NB- The vacant cells against certain voltage class indicates that assets of such voltage class do not exist under the particular Transmission licence.

The normative O&M expenses for each subsequent year of the Control Period has been 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 Performance Review in terms of efficiency factors.

For the new transmission licensees such as Jaigad Power Transco Ltd, Adani Power Maharashtra Ltd. and for any other future private transmission licensee in Maharashtra, the year-wise O&M norms as determined for MSETCL shall be the applicable norms for transmission assets added by such new transmission licensee(s) for respective year during the next Control Period.

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.

Proposal for Tenure of InSTS Usage within Maharashtra:

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.

Another major issue is to ensure uniformity in sharing of charges for Intra State Transmission Usage among various TSUs. Further, no undue cost burden should be imposed on the TSUs for excess utilization of their Transmission Capacity Rights (TCRs) for limited duration subject to system considerations. In view of these, the following mechanism is proposed for the next Control Period.

a) Average of CPD and NCPD (to be termed as Base TCR) for each long term TSU to be arrived at based on recorded data for previous 12 months, before submission of MYT Petition.

b) Existing long term TSU with **recorded Demand** upto Base TCR (i.e. average of CPD & NCPD) will not be subjected to payment of short term transmission charges.

c) However, long term TSU with **recorded demand** > Base TCR < Contracted Capacity would require to make payment of short term Transmission charges for the recorded demand in excess of Base TCR (the short term transmission charges are same as long term, but would be used to reduce long term charges).

d) For **recorded demand** greater than Contracted capacity (termed as Transmission Capacity Right - TCR), the TSU will have to bear additional transmission charges as specified in MERC Transmission Open Access Regulations, 2005 or as amended from time to time.

e) Equal weightage to be given to CPD and NCPD in calculation of base transmission tariff.

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."*

<u>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.</u>

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

Marginal Participation(MP) Method

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**.

Following the Approach Paper on sharing of Transmission Charges and Losses, CERC has published draft Regulations on the same incorporating the comments received on the Approach Paper. CERC, after due consideration of the alternative methodologies for allocation of transmission charges and the comments received from various stakeholders has considered implementation of the Point of Connection (PoC) methodology based on a hybrid method, which brings together the strengths of both the Marginal Participation and the Average Participation Method discussed in the approach paper.

Under the recently circulated Draft Regulations for sharing of transmission charges and losses for inter-State regional transmission system, CERC has proposed that for implementation, in the first two years, the Commission will apply transmission charges and losses based on a combination of PoC methodology and a Postage Stamp (i.e., one single charge / loss percentage for all DICs - Designated Inter-State Customers) methodology in a ratio of 50:50. The Commission may consider increasing the locational signal by reducing the proportion of the postage stamp component over time.

However, 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 the Indian Electricity Grid Code, 2010 notified on April 28, 2010, which penalizes reactive energy drawal and rewards reactive energy injection @ 10.00 paise/kVARh, w.e.f April 1, 2010, escalated at 0.5 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 @ 10.00 paise/kVARh, w.e.f April 1, 2010, escalated at 0.5 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 Regulation 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 0.10/RkVAh for additional injection. - Incentive at the rate of Rs 0.10/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 0.10/RkVAh for additional drawal. - Penalty at the rate of Rs 0.10/RVkAh for additional drawal. - Nil

Reactive Energy charges for Generators

A generating station should inject/absorb the reactive energy in to the grid as per the directions of State Load Despatch Centre. Such injection/absorption may be undertaken on the basis of machine capability and in accordance with the directions issued by

SLDC. A rate of charge for such reactive energy exchange for the applicable duration (injection or absorption) will be levied/compensated on generating station at rate of 10.00 paise/kVArh for FY 2010-11 escalated at 0.5 paise/kVArh annually in subsequent years, unless otherwise revised by Commission.

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.

For the next Control Period, it is proposed to continue with the existing norms for transmission system availability as well as incentive mechanism as outlined under MERC Tariff Regulations, 2005.

5.5.6 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

5.5.6.1 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.

Proposal:

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.

5.5.6.2 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.

5.5.6.3 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

5.5.6.4 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 Co-incident Peak Demand (CPD)	Under this approach, the annual transmission charges shall be shared amongst the transmission system users based on their contribution to system maximum demand or	o This approach is in line with the approach for determining the Cost of Service for determining the actual cost involved in servicing the consumers. o The Discom, as a demand-

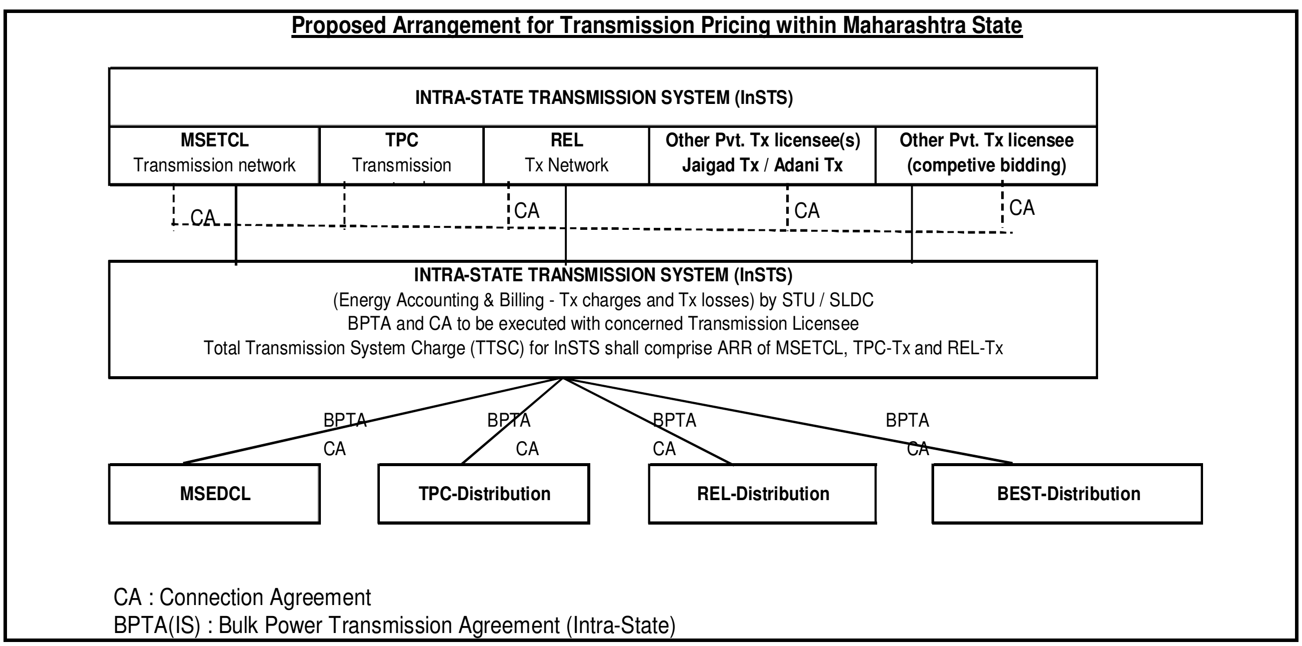
Method for Transmission Tariff Design	Principle	Key Considerations and Concerns
	co-incident peak demand (CPD).	aggregator, would benefit from the diversity of consumer mix which would result in a gap between the non-coincident peak and the coincident peak and therefore, the Discom would incur a lower 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.
Alternative-1D: **Share based on both CPD and NCPD (Hybrid approach)**	Under this approach, the annual transmission charges shall be shared amongst the transmission system users based on their contribution to both Coincident Peak Demand as well as Non coincident peak demand.	o Under this approach the CPD and NCPD shall be given equal weightage (50: 50). o Considering NCPD in addition to CPD would incentivise the TSUs to manage their individual peak demand.

Suggestion:

For the next Control Period, it is proposed to determine Transmission Tariff based on share or contribution of TSUs towards 'Co-incident peak' demand (CPD) based on co-incident peak demand recorded in the previous year and 'Non Co-incident Peak' demand (NCPD) based on non co-incident peak demand recorded in the previous year. It is also proposed that equal weightage (50: 50 ratio) for Co-incident peak demand and Non Co-incident Peak demand shall be given to determine the base TCRs of each TSUs.

5.5.7 Proposed Mechanism for Intra-State Transmission Pricing for the new Control Period

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 and non-coincident peak demand of the State. The block diagram shown below depicts the proposed 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-T, RInfra-T, Jaigad Power Transco, Adani Power Transco and any other private transmission licensee in future.

b) Each transmission licensee including existing transmission licensees (i.e. MSETCL, TPC-T, RInfra-T, Jaigad Power Transco, Adani Power Transco) shall submit its MYT 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) The Commission shall, in the beginning of the Control Period, approve the year-wise Aggregate Revenue Requirement of each transmission licensee for the new Control Period.

d) Total of the yearly Aggregate Revenue Requirements for all Transmission licensees; less the deductions, as approved by the Commission over the new control period, 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) for the respective year of the Control Period.

$$TTSC_1 = \sum_{i=1}^{n} (ARRi-NTi-Oi)$$

Where,

$TTSC_1$ = Pooled cost of year 1 of the Control period

n = Number of Transmission Licensee

ARR_i = Yearly ARR approved by the Commission for i^{th} Licensee

NTi = Approved level of non-tariff income for i^{th} Licensee

Oi = Approved level of income from other business of the i^{th} Licensee

e) 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.

f) The Commission shall approve yearly 'Base Transmission Capacity Rights' (Base TCR as average of Co-incident Peak Demand and Non-Coincident Peak Demand for TSUs as projected for 12 monthly period of each year of the Control Period) representing the "Capacity Utilisation' of Intra-State transmission system and accordingly determine yearly 'Base Transmission Tariff' for the same.

Base Transmission Capacity Rights $= \underline{(CPD_1+NCPD_1)/2}$

Where,

CPD_1 = Average of monthly Coincident Peak Demand for the 1st year of Control period

$NCPD_1$ = Average of monthly Non-Coincident Peak Demand for the 1st year of Control period

NB: The yearly CPD and NCPD to be considered for determination of the yearly Base Transmission Capacity Rights shall be computed at the beginning of the MYT control period based on the demand projections made by various TSUs connected to the Intra-State transmission system. Further on completion of the each year of the control period, SLDC shall submit the recorded CPD and NCPD data for past 12 monthly periods. Based on the same, the base TCR shall be suitably revised at the time of review periods in the next MYT control period.

g) '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).

Base Transmission $Tariff_1$ (long term/medium term) (Rs/kW/month or Rs/MW/day)	$= TTSC_1/\left((CPD_1+NCPD_1)/2\right)$

Short term Transmission Tariff $_1$ (Rs/kWh)	$= TTSC_1 / \sum_{i=1}^{n}$ (Energy Transmitted by Tx_i)

Where,

$TTSC_1$ = Pooled cost of year 1 of the Control period

CPD_1 = Average of monthly Coincident Peak Demand for the 1st year of Control period

$NCPD_1$ = Average of monthly Non-Coincident Peak Demand for the 1st year of Control period

n = Total number of Transmission Licensee in that particular year of control period

Tx_i = ith Transmission Licensee

h) 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.

i) 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.

j) 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.

k) 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.

l) 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'.

m) 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

n) As regards addition of new Transmission Licensees during the next control period, such transmission licensees will have to submit an MYT Petition projecting the Aggregate Revenue Requirement of the Licensee over the years of the control period and the Commission shall approve revenue cap/ARR for such years of the control period.

o) 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.

p) Any revisions in base Transmission Tariff occurring due to the variation in the actual and approved CPD and NCPD or due to addition of new transmission licensees to the system shall be made during the time of mid-term review or at the end of the MYT Control Period.

SLDC shall continue to undertake State-wide energy accounting and determination of transmission losses for intra-State transmission system.

6 Norms and Principles for Determination of Wheeling Charges for Distribution 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 Distribution Wires Business (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. For the second Control Period, it is proposed that Aggregate Revenue Requirement of the Wires Business, shall be 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 Chapter-3 of this Approach Paper;

b) Depreciation: General principles have already been discussed earlier in Chapter-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 Chapter-3 of this Approach Paper;

e) Adjustment of Contribution to contingency reserves: General principles have already been discussed earlier in Chapter-3 of this Approach Paper.

Wheeling charges = Aggregate Revenue Requirement, as computed above, minus:

f) Non-tariff income; and

g) Income from Other Business.

h) Receipts on account of additional surcharge on charges of wheeling.

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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 wires 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 wires 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* ***<u>nothing contained in this section shall apply to a local authority engaged</u>****, 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 wires assets. 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 Business 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 17: 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 wires 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. However, at present, none of the distribution licensees are maintaining separate accounting for the assets and activities for Wire Business and Supply Business. Hence, it is proposed that the following allocation matrix may be followed as an interim measure for the purpose of calculation of wheeling charge:

Table 18: Proposed allocation matrix for expense segregation of Wires and Supply Business

Particulars	Wires Business (%)	Supply Business (%)
Power Purchase Expenses	0%	100%
Standby Charges	0%	100%
Employee Expenses	60%	40%
Administration & General Expenses	50%	50%
Repair & Maintenance Expenses	90%	10%
Depreciation	90%	10%
Interest on Long-term Loan Capital	90%	10%
Interest on Working Capital and on consumer security deposits	10%	90%
Bad Debts Written off	10%	90%
Other Expenses	0%	100%
Income Tax	90%	10%
Transmission Charges intra-State	0%	100%
Contribution to contingency reserves	90%	810%
Return on Capital Employed	80%	20%
Non Tariff Income	80%	20%

However, a separate study is being undertaken by the Commission for approval of operating procedures for supplying power to consumers under parallel licence situation. As part of this study, it is envisaged that the Commission will determine the operating procedures, segregation of assets and responsibilities of Wires and Supply business, to facilitate parallel licence operations in Maharashtra. Hence, matters pertaining to segregation of wires and supply business shall be dealt in accordance with the Commission's rulings in this regard. However, as an interim measure, the proposed matrix may be used to determine wheeling charges.

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), the wheeling charges in terms of Rs/kW/month are summarised below:

Voltage	RInfra-D		TPC-D	
	Wheeling Charge (Rs/kW/ month)	**Wheeling Loss (%)**	**Wheeling Charge (Rs/kW/ month)**	**Wheeling Loss (%)**
HT level	108	1.50%	78	0.66%
LT level	121	9.00%	160	0.66%

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 19: 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%

The Commission in its Order dated August 17, 2009, in Case No. 116 of 2008 has approved wheeling charge for MSEDCL as under:

	MSEDCL		
Particulars	**33 kV**	**22 kV/11 kV**	**LT level**
Wheeling Charge (Rs/kWh)	0.05	0.25	0.43
Wheeling losses (%)	6%	9%	14%

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."*

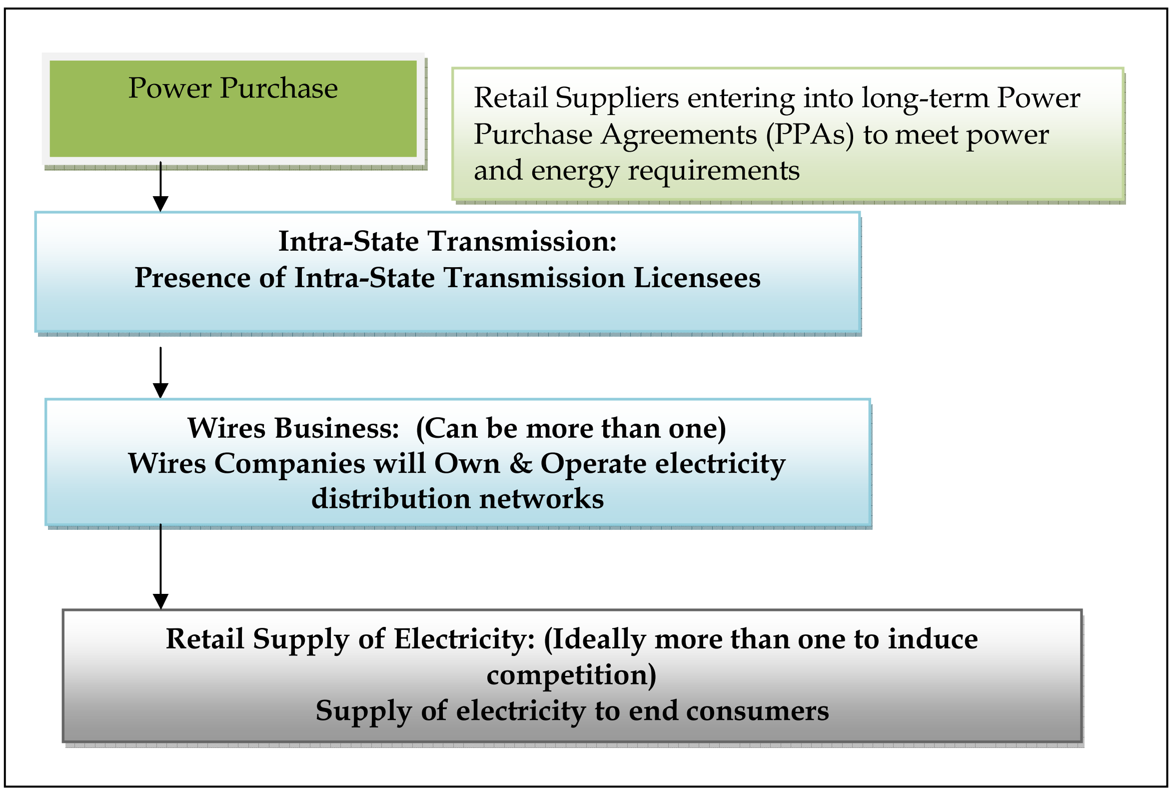
In India, the parallel distribution companies with common carrier/independent distribution network as envisaged in the EA 2003 are yet to come up in spite of the enabling legal framework provided in the EA 2003. The consumers continue to buy power from monopoly distribution licensees without any choice 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

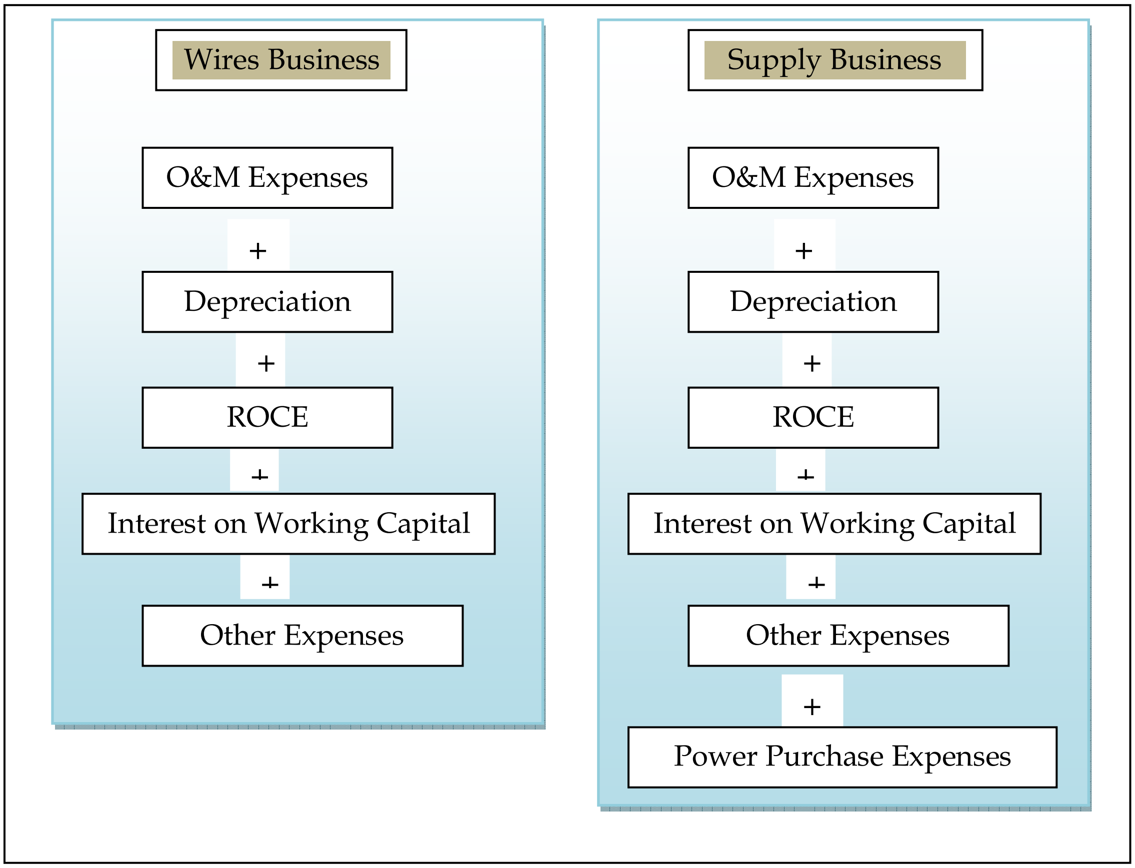


With a view to introduce competition, in the long-term, the Wires Business (covering the distribution network) may need to be separated from Retail Supply Business. The retail supply licensees should be able to supply power to any consumer (irrespective of the load and supply voltage) through the existing distribution lines/network subject to payment of wheeling charges to the owner of the Wires Business. Requirement of meeting Universal Service Obligation (USO) would form an essential part of retail supply licence conditions, to prevent cherry picking of consumers. Under such a framework:

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 Electricity Act, 2003 will have to be amended, since the present provisions of the EA 2003 mandate a unified distribution licence, with the licensee responsible for the Wires Business as well as the Retail Supply Business. As and when the EA 2003 is amended, the distribution licences issued to the distribution licensees would have to be amended accordingly, and the necessary regulatory framework to ensure that the wires assets are 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:



However, a separate study is being undertaken by the Commission for approval of operating procedures for supplying power to consumers under parallel licence conditions. Hence, matters pertaining to segregation of wires and supply business shall be dealt in accordance with the Commission's rulings in this regard.

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. It is felt 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 20: 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

The inter-State comparison has been done based on type of licence area, as discussed below:

a) RInfra-D, TPC-D and BEST have been benchmarked with their own past performances. Comparison of their performance has also been done with **city based licensees** (Urban profile) like BRPL, BYPL, NDPL, CESC, Torrent Power Limited. etc.

b) MSEDCL has been benchmarked with its own past performances. Comparison of their performance has also been done with **State based Licensees having heterogeneous profile**.

In the draft Approach Paper, different benchmarks for different distribution licensees were proposed, considering the peculiarities. However, in the expert consultation process, Utilities submitted that Utilities in Maharashtra are not comparable with other Utilities in India. The comments and suggestions received from the expert group (both as written submissions and views expressed during expert consultation meeting held on October 9, 2009) on the benchmarking exercise, have been studied. It is felt that the benchmarking exercise will not achieve desired result if Utility is not benchmarked with performance of other industry players. Hence, benchmarking norms have been derived based on the past performance and inter-State comparison of the Utilities.

The comparison of various parameters with selected distribution licensees across India having similar profile, has been undertaken to give a better understanding of performance of Utilities in Maharashtra vis-à-vis other Utilities across India.

6.4 Wheeling Loss determination

The Commission, in its previous Tariff Order, has determined the wheeling loss applicable in kind for wheeling transactions, based on the technical loss at various voltage levels. The Commission has always maintained that the open access consumers have to bear only the technical losses in the system, and should not be asked to bear any part of the commercial losses. However, for determination of wheeling loss, the technical loss of distribution system needs to be projected by the Utilities in their respective Business Plans. **Hence, it is proposed that the Commission shall determine the wheeling loss trajectory for the Utilities based on the Business Plan submitted by the Utilities.**

6.5 *Operation & Maintenance Expenses - Norm for Wires Business*

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. The primary growth driver for A&G expenses is the number of consumers served by the Utility. Some of the key heads of A&G expenses linked to number of consumers are as under:

i. Numbers of administrative offices required to rovide services to the consumers.

ii. Travelling cost incurred in travelling of employees of Utilities to provide necessary services to the consumers, 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.

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).

In the draft Approach Paper, Norms were proposed in proportion to the sales in units. However, in the expert consultation process, RInfra submitted that

"MPERC in its MYT Tariff Regulations has notified that:

Operation and Maintenance expenses

3.28 The O&M expenses comprise of employee cost, repairs & maintenance (R&M) cost and administrative & general (A&G) cost. The norms for O&M expenses have been fixed on the basis of metered consumers, metered sales and 33 &11 KV network length. These norms exclude terminal benefits to be paid to employees, taxes to be paid to the Government or local authorities and fees to be paid to MPERC, which the Distribution Licensee shall claim separately.

3.29 The net O&M expenses for each year of the tariff period shall be computed on the basis of projected number of metered consumers, metered sales, total network length of 11 & 33 KV, voltage levels and allowable rates for each of these parameters for the year under consideration. The Distribution Licensee shall submit in his petition the basis of arriving at these projected values.

3.30 Net O&M rates per thousand metered consumers, metered MU sales and 33 &11 KV Network Length ('100 Kms) allowed for each year of the control period are as per the table given below:

Table 2: Net O&M charges for the tariff period*

O&M charges (Rs. In lakhs)	FY07	FY08	FY09
For Metered Consumers (Rs lakh/1000 Consumer)	6.10	6.50	6.90
For Installation of additional pre-paid meters during the year	50% of the cost of meters	50% of the cost of meters	50% of the cost of meters
For Metered Sales (Rs Lakh/MU)	2.21	2.35	2.49
For Network length (Rs Lakh/100 ckt km)	15.10	16.00	17.00
For Transformation (Rs Lakh/MVA)	1.44	1.53	1.62

Hence, it is suggested that similar exercise be carried out for Maharashtra, and O&M expenses are not only benchmarked against the sales but also against all the critical drivers affecting the O&M expenses such as network size, sales and number of consumers. Network size may be represented by line length or transformation capacity.

Further, we will like to add that here are many factors that affect a Utility's expenditure on operations and maintenance, and many such factors, most often, are not within reasonable control of the utility, as they are arise on account of levies by external agencies. These include, but are not limited to – Road Re-instatement Charges of MCGM, Security Guard Board Charges, Rents and Taxes, water charges, wage revision pursuant to agreement with Labour Union, etc. It is suggested that increase in O&M expenses on account of such factors must be considered extraneous / force majeure and allowed as a pass through, over and above the normative allowance."

After the expert consultation process, the distribution network details, viz., distribution line length, transformation capacity, etc., were sought from the Utilities, for the purpose of benchmarking. However, apart from TPC-D and MSEDCL, no other Utility has submitted the requisite information. Also, it would be difficult for the Commission to verify or cross-check the distribution line length, transformation capacity, etc. Hence, after considering the merits and demerits of the above approaches, it is proposed that for distribution licensees, the norm for employee expenses, A&G expenses and R&M expenses be derived separately, and the three components are added to specify consolidated norm for O&M expenses. The following approach is proposed for determination of Composite operational norms for O&M expenses:

Employee expenses	:	linked to number of consumers and per unit of sales, based on past five years' trend. Weightage of number of consumers and per unit of sales is proposed to be considered as 50% each.
A&G expenses	:	linked to number of consumers, and based on past five years' trend.
R&M expenses	:	Percentage of Opening GFA for the year

Escalation factor of 5.72% is proposed for the composite O&M Norms, based on CERC Tariff Regulations, 2009.

6.5.1 Benchmarking O&M expenses for Wheeling Business of City based Distribution Licensees

The benchmarking has been done in the following manner:

1. The O&M Cost per unit of sales for various Distribution Licensees has been calculated, and then median of the year-wise numbers and the 4-year average has been calculated.
2. Variance of O&M cost per unit of Distribution Licensees with respect to median value has been calculated to derive variance of O&M cost indicating the scope for optimising the O&M Cost.

The inter-State ratio analysis of various parameters on which the employee expenses are dependent, viz., sales and number of consumers, has been summarised below:

Table 21: Inter-State Ratio Analysis for benchmarking of O&M Expenses

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
CESC	0.40	0.47	0.48	0.49	0.46
BYPL	0.75	0.51	0.64	0.59	0.62
BRPL	0.46	0.45	0.51	0.48	0.48
NDPL	0.52	0.46	0.50	0.47	0.49
RInfra-D	0.57	0.64	0.65	0.65	0.63
BEST	0.67	0.57	0.59	0.61	0.61
TPL- Ahmedabad		0.48	0.34	0.33	0.34
TPL- Surat			0.27	0.26	0.26
Median of O&M Cost	**0.54**	**0.48**	**0.51**	**0.49**	**0.48**
Variance in Cost					
RInfra-D	0.02	0.16	0.14	0.17	0.14
BEST	0.13	0.09	0.09	0.12	0.13

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
Andhra Pradesh Discoms - Consolidated	0.28	0.27	0.25	0.30	0.28
Karnataka Discoms - Consolidated	0.41	0.35	0.35	0.34	0.36
Gujarat Discoms - Consolidated	0.28	0.27	0.32	0.30	0.29
Rajasthan Discoms Consolidated	0.28	0.29	0.30	0.35	0.30
MSEDCL	0.44	0.43	0.51	0.51	0.47
Median of O&M Cost	0.28	0.29	0.32	0.34	0.30
Variance in Cost					

MSEDCL	0.16	0.14	0.19	0.17	0.17

As seen from the above Tables:

- BEST: Variance in O&M cost as compared to median value of Other Utilities has been in the range of 9 to 13 paise per unit of sales. 4-year Average Variance is 13 paise per unit of sales. Hence, it is proposed that targeted O&M cost reduction for BEST in the second Control Period shall be 12 paise per unit of sales, spread over five years.
- RInfra-D: Variance in O&M cost as compared to median value of Other Utilities has been increasing from 2 paise per unit of sales to 17 paise per unit of sales. 4-year Average Variance is 14 paise per unit of sales. Since, the variance in performance for BEST and RInfra-D is almost similar, it is proposed that O&M cost reduction for RInfra-D in the second Control Period shall be 12 paise per unit of sales, spread over five years.
- MSEDCL: Variance in O&M cost as compared to median value of Other Utilities has been in the range of 14 to 17 paise per unit of sales. 4-year Average Variance is 17 paise per unit of sales. Hence, it is proposed that O&M cost reduction for MSEDCL in the second Control Period shall be 15 paise per unit of sales, spread over five years. It may be noted that for inter-Utility comparison for MSEDCL, the values for the individual DISCOMs in other comparable States have been aggregated to provide comparable values, since MSEDCL supplies electricity to the entire State of Maharashtra, excluding Mumbai licence area.

6.5.2 O&M expense Norms for Wheeling Business of 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 have been analysed below. Sales, number of consumers and GFA approved by the Commission have been used for benchmarking purposes as tabulated below:

Sales **MU**

Licensee	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**

Licensee	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	23,640	23,628	25,390	26,662
BEST	944,192	944,192	959,984	975,823

GFA **Rs Crore**

Licensee	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 22: 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 following steps have been undertaken to derive norms for Employee expenses:

1. Weightage of various Parameters applied to calculate the value of
   a) **Employee expenses:** linked to number of consumers and per unit of sales, based on past four years' trend. Weightage of number of consumers and per unit of sales has been considered as 50% each, respectively.
   b) **A&G expenses**: linked to number of consumers based on past four years' trend.
   c) **R&M expenses:** Percentage of Opening GFA for the year

Adjusted employee expense for FY 2011-12: The approved value of FY 2009-10 has been escalated by 5.72% (escalation rate as prescribed in CERC Tariff Regulations, 2009) for two years to derive normative value for FY 2011-12.

The ratio analysis is given in the Table below:

Table 23: Ratio Analysis for benchmarking Employee Expenses

Employee Expense/unit **Rs/kWh**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average	Adjusted Average for FY 2011-12
RInfra-D	0.15	0.17	0.17	0.18	0.18	0.20
TPC-D	0.02	0.03	0.04	0.09	0.09	0.10
BEST	0.18	0.17	0.17	0.18	0.18	0.20

Employee Cost (Rs. lakh/ '000 consumers)

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average	Adjusted Average for FY 2011-12
RInfra-D	4.47	4.95	5.24	5.46	5.46	6.10
TPC-D	NA					
BEST	7.33	7.05	7.44	7.86	7.86	8.78

As seen from the above Tables:

- RInfra-D and BEST: While the employee expenses have been increasing in absolute terms, the adjusted employee expenses for FY 2011-12 is around 20 paise per unit of sales over the years, and have been around Rs. 6.10 lakh to Rs. 8.78 lakh per thousand consumers, say Rs 9 lakh per thousand consumer. The norm for distribution business for employee expenses for RInfra-D and BEST for FY 2011-12, before accounting for efficiency improvement, is:
    - 20 paise per unit of sales, plus
    - Rs 9 lakh per thousand consumer
- 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 and also with the switchover of RInfra-D consumers to TPC-D, there will be increase in number of consumers as well as sales. Hence, the norm for employee expenses before accounting for efficiency improvement, is 12 paise per unit of sales for FY 2011-12.

Based on the allocation matrix proposed earlier in this Chapter, the employee expenses pertaining to wires business, has been derived

Particulars	Wires Business (%)	Supply Business (%)
Employee Expenses	60%	40%

Hence, employee expense norm for FY 2011-12 for wires business, before accounting for efficiency improvement, is as under:

- RInfra-D and BEST:
    - 12 paise per unit of wheeled energy, plus;
    - Rs 5.27 lakh per thousand consumer
- TPC-D: 7.2 paise per unit of wheeled energy.

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 24: 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
RInfra-D	96	99	105	112
TPC-D	11	12	14	14
BEST	73	68	73	77

The adjusted A&G expenses have been derived by using the same methodology as adopted for deriving adjusted Employee expenses.

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 25: 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	Adjusted Average for FY 2011-12

TPC-D	0.05	0.05	0.06	0.05	0.05	0.06

A&G Expense/consumer **Rs lakh /'000 Consumer**

Licensee	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average	Adjusted Average for FY 2011-12
RInfra-D	3.80	3.69	3.86	3.98	3.84	4.29
BEST	7.71	7.24	7.55	7.88	7.60	8.49

Hence, it is proposed that:

- RInfra-D and BEST: While the A&G expenses have been increasing in absolute terms, the adjusted A&G expenses for FY 2011-12 have ranged around Rs. 4 lakh to Rs 8.5 lakh per thousand consumers. The norm for distribution business for A&G expenses for RInfra-D and BEST for FY 2011-12, before accounting for efficiency improvement, is:
    - Rs 8.5 lakh per thousand consumer
- Hence, the proposed norm for A&G expenses for TPC-D before accounting for efficiency improvement, is 8 paise per unit of sales for FY 2011-12.

Based on the allocation matrix proposed earlier in this Chapter, the A&G expenses pertaining to wires business, has been derived

Particulars	Wires Business (%)	Supply Business (%)
A&G Expenses	50%	50%

Hence, A&G expense norm for FY 2011-12 for wires business, before accounting for efficiency improvement, is as under:

- RInfra-D and BEST:.
    - Rs 4.25 lakh per thousand consumer
- TPC-D: 4 paise per unit of wheeled energy.

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 26: 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 27: Intra-State Ratio Analysis for benchmarking R&M Expenses

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%

As seen from the above Tables:

- 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 norm for R&M expenses for TPC-D, before accounting for efficiency improvement, 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 intra-State comparison, as shown above. The norm for R&M expenses for RInfra-D and BEST, before accounting for efficiency improvement, is 4.5% of opening GFA of the financial year.
- Based on the allocation matrix proposed earlier in this Chapter, the R&M expenses pertaining to wires business will be allocated as per matrix tabulated below:

Particulars	Wires Business (%)	Supply Business (%)
R&M	90%	10%

Hence, R&M expense norm for FY 2011-12 for wires business, before accounting for efficiency improvement, is as under:

Licensee	Norm
RInfra-D	4.05%
TPC-D	1.35%
BEST	4.05%

6.5.3 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 28: O&M Expenses of MSEDCL (State based Distribution Licensee)

Rs Crore

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
Employee Expenses	1,593	1,782	2,276	2,512
A&G Expenses	148	189	201	213
R&M Expenses	416	436	458	482
O&M Expenses	**2,157**	**2,407**	**2,935**	**3,207**

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
Sales (MU)	49,147	55,715	57,796	65,124
Consumer (Nos.)	11,963,681	13,342,227	14,531,680	15,635,990
GFA (Rs. Crore)	9428	10531	10831	11761

The same methodology as adopted for City based licensees has been adopted for deriving adjusted value of Employee, A&G, and R&M expenses.

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 29: Ratio Analysis for MSEDCL for benchmarking Employee Expenses

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average	Adjusted Average for FY 2011-12
Rs/ kWh	0.16	0.16	0.20	0.19	0.19	0.22
Rs Lakh/ '000 Consumer	6.66	6.68	7.83	8.03	8.03	8.98

Table 30 : Ratio Analysis for MSEDCL for benchmarking A&G Expenses

Rs lakh /'000 Consumer

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average	Adjusted Average for FY 2011-12
A&G Cost/'000 consumer	1.24	1.42	1.38	1.36	1.35	1.51

Table 31: Ratio Analysis for MSEDCL for benchmarking R&M Expenses

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10	4 year-Average
MSEDCL	4.42%	4.14%	4.23%	4.10%	4.22%

The O&M Norms for FY 2011-12 for MSEDCL, before accounting for efficiency improvement, are as under:

- Employee Expenses:
  - 22 paise per unit of sales plus
  - Rs 8.98 lakh per thousand consumer
- A&G expenses
  - Rs 1.51 lakh per thousand consumer
- R&M expenses
  - 4.5% of opening GFA of distribution business

Based on the allocation matrix proposed earlier in this Chapter, the O&M expenses pertaining to wires business have been derived:

Particulars	Wires Business (%)	Supply Business (%)
Employee Expenses	60%	40%
A&G Expenses	50%	50%
R&M Expenses	90%	10%

Hence, O&M expense norm for FY 2011-12 for wires business of MSEDCL, before accounting for efficiency improvement, is as under:

- Employee Expenses:
    - 13 paise per unit of wheeled energy plus
    - Rs 5.40 lakh per thousand consumer
- A&G expenses
    - Rs 0.76 lakh per thousand consumer
- R&M expenses
    - 4.05% of opening GFA of Wires business

In addition to the distribution licensees mentioned above, the Mula Pravara Electric Co-operative Society (MPECS) distributes electricity in 183 villages spread over 5 Talukas in Ahmednagar District. The Commission has issued Tariff Order dated February 23, 2007 in the matter of determination of Tariff for FY 2006-07. After this Order, MPECS did not file MYT Petition and APR Petition, as required under MERC Tariff Regulations, 2005. MPECS has filed tariff Petition for FY 2009-10, which is under consideration of the Commission. It was felt that for the purpose of O&M Norm benchmarking, it will not be appropriate to determine norm based on FY 2006-07 levels. Hence, it is proposed that for MPECS, the O&M Norm determined for MSEDCL would be applicable.

6.5.4 Composite O&M expenses Norm for Wires Business in Maharashtra

Based on the above analysis, before accounting for efficiency improvement, the following normative O&M expenses can be considered for Utilities in Maharashtra:

A) Distribution Business

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales (Paise/kWh)	22	20	20	20	22
For Consumers (Rs Lakh/'000 Consumers)	11	18	18	**NA**	11
For GFA (% of Opening GFA)	4.50%	4.50%	4.50%	1.50%	4.50%

B) Wires Business

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Wheeled Energy (Paise/kWh)	13	12	12	11	13
For Consumers on Wires Business	6	10	10	**NA**	6

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
(Rs Lakh/'000 Consumers)					
For GFA of Wires Business (% of Opening GFA)	4.05%	4.05%	4.05%	1.35%	4.05%

However, in order to account for efficiency improvement as indicated by variance in O&M expenses as compared to median value of Other Utilities based on inter-State comparison, O&M expense reduction for Wires Business in the second Control Period is proposed as under:

a) RInfra-D and BEST: 8 paise per unit of sales, spread over five years.

b) MSEDCL: 10 paise per unit of sales spread over five years.

Hence, for second Control Period, the Norms would be as tabulated below.

FY 2011-12

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Wheeled Energy (Paise/kWh)	11	10	10	11	11
For Consumers in Wires Business* (Rs Lakh/'000 Consumer)	6	10	10	**NA**	6
For GFA of Wires Business (% of Opening GFA)	4.05%	4.05%	4.05%	1.35%	4.05%

FY 2012-13

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Wheeled Energy (Paise/kWh)	10	9	9	12	10
For Consumers in Wires Business* (Rs Lakh/'000 Consumer)	6.50	10.06	10.06	NA	6.50
For GFA of Wires Business (% of Opening GFA)	4.05%	4.05%	4.05%	1.35%	4.05%

FY 2013-14

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Wheeled Energy (Paise/kWh)	8	7	7	13	8
For Consumers in Wires Business* (Rs Lakh/'000 Consumer)	6.9	10.6	10.6	NA	6.9
For GFA of Wires Business (% of Opening GFA)	4.05%	4.05%	4.05%	1.35%	4.05%

FY 2014-15

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Wheeled Energy (Paise/kWh)	7	5	5	13	7
For Consumers in Wires Business* (Rs Lakh/'000 Consumer)	7.3	11.2	11.2	NA	7.3
For GFA of Wires Business (% of Opening GFA)	4.05%	4.05%	4.05%	1.35%	4.05%

FY 2015-16

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Wheeled Energy (Paise/kWh)	5	4	4	14	5
For Consumers in Wires Business* (Rs Lakh/'000 Consumer)	7.7	11.9	11.9	NA	7.7
For GFA of Wires Business (% of Opening GFA)	4.05%	4.05%	4.05%	1.35%	4.05%

Note: *Consumers using Wires Business indicates consumers using Wires Business of a Distribution Licensees. For Example, for RInfra-D: It would cover RInfra-D consumers who use wires as well as supply services of RInfra-D, and TPC-D consumers using RInfra-D's wires business only for wheeling of electricity.

It may be noted that after taking into account efficiency improvement for Wires Business, Paise/kWh component of Norm is reducing. However, in absolute terms O&M expenses for Utilities is increasing. Sample illustration taking into consideration average increase in sales and GFA as 5% and increase in number of wheeling consumers as 2.5% and also assuming that entire sales of Distribution Business is being wheeled by the Distribution licensee, is as under:

Assumption of Inputs for Norm Calculation

FY 11-12	MSEDCL	RInfra-D	BEST	TPC-D
Wheeled Energy (MU)	68380	9110	4470	2770
Consumers using Wires Business (Number)	16026890	2877531	1000219	27329
GFA of Wires Business (Rs Crore)	12349	2737	1376	507

FY 12-13	MSEDCL	RInfra-D	BEST	TPC-D
Wheeled Energy (MU)	71799	9565	4693	2908
Consumers using Wires Business (Number)	16427562	2949469	1025224	28012
GFA of Wires Business (Rs Crore)	12966	2874	1444	533

Based on the assumed inputs for calculation of Norm, the O&M Expenses for FY 2011-12 and FY 2012-13 are as under:

In Rs Crore

FY 11-12	MSEDCL	RInfra-D	BEST	TPC-D
Wheeled Energy Component	752	91	45	31
Consumers using Wires Business Component	986	274	95	0
GFA of Wires Business Component	494	109	55	8
Total	**2232**	**475**	**195**	**39**

FY 12-13	MSEDCL	RInfra-D	BEST	TPC-D
Wheeled Energy Component	691	82	40	34
Consumers using Wires Component	1068	297	103	0
GFA of Wires Business Component	519	115	58	8
Total	**2278**	**494**	**201**	**42**

Note: Sample illustration has used assumed input parameters and these numbers should be referred only for giving fair idea to the Utilities, regarding movement of O&M expenses.

It may be noted that the net increase in O&M Charges reflect yearly increase provided for Inflation (@5.72%) minus variance on account of the efficiency improvement requirement based on benchmarking with Utilities of similar profile. Since the Norm is linked to output parameters like sales, number of consumers and GFA, it will incentivise the Distribution Licensee to increase their efficiency and increase the coverage of their consumer base.

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.

The Guidelines are intended to verify the prudence of capital investments made by Utilities 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 the 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 Business Plan filed by the Distribution Licensees.

6.7 *Wheeling Charge Determination*

The wheeling charges of the Distribution Licensee shall be determined by the Commission on the basis of an Application for determination of tariff made by the Distribution Licensee in accordance with the MYT Regulations. It is proposed that the Wheeling Charges may be denominated in terms of Rupees/kWh or

Rupees/kW/month, for the purpose of recovery from the Distribution System User, or any such denomination, as stipulated by the Commission from time to time.

7 Norms and Principles for Determination of Revenue Requirement and Tariff for Retail Supply Business

The 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 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 Chapter-3 of this Approach Paper;

d) Depreciation: General principles have already been discussed earlier in Chapter-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 Chapter-3 of this Approach Paper;

g) Adjustment of Contribution to contingency reserves: General principles have already been discussed earlier in Chapter-2 of this Approach Paper.

h) Provisioning for bad debts: General principles have already been discussed earlier in Chapter-2 of this Approach Paper;

Minus:

i) Non-tariff income;

j) Income from Other Business;

k) Receipts on account of cross-subsidy surcharge; and

7.1 Power Procurement Guidelines

The Distribution (Supply) Licensee purchases power from different sources either through long-term Power Purchase Agreements or medium-term Power Purchase Agreements or through short-term contracts.

For effective implementation of the Multi Year Tariff Regime, it is important that the Licensees shall prepare their 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, medium-term and short-term power procurement by Distribution Licensees. The proposed guidelines in this regard are given below:

Power procurement Plan

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 as per procedure described in Chapter-2 of this Approach Paper. The long-term power procurement plan should be prepared considering the:

a) A quantitative forecast of the unrestricted demand for electricity from each tariff category within his area of supply over the Control Period;
b) An estimate of the quantities of electricity supply from the identified sources of generation and power purchase;
c) An estimate of availability of power to meet the base load and Peak load requirement.
d) Provided that the estimate should be monthly estimation of demand and supply both in Mega-Watt (MW) as well as expressed in Million Units (MU).
e) Standards to be maintained with regard to quality and reliability of supply, in accordance with the MERC (Standards of Performance of Distribution Licensees, Period for Giving Supply and Determination of Compensation) Regulations, 2005, as amended from time to time;
f) Measures proposed to be implemented as regards energy conservation and energy efficiency;
g) The requirement for new sources of power generation and/or procurement, including augmentation of generation capacity and identified new sources of supply, based on (a) to (d) above;
h) The plan for procurement of power including quantities and cost estimates for such procurement:

i) Provided that the forecast/estimate contained in the long-term procurement plan shall be separately stated for peak and off-peak periods, in terms of quantities of power procured (in millions of units of electricity) and maximum demand (in MW / MVA):
j) Provided further that the forecasts/estimates shall be prepared for each month over the Control Period:
k) Provided also that the long-term procurement plan shall be a cost-effective plan based on available information regarding costs of various sources of supply.
l) Explanation – for the purpose of this Regulation, the term "peak period" shall mean such block of three (3) continuous hours during a twenty-four (24) hour period representing maximum demand for power by the Distribution Licensee.
m) Short-term power procurement proposed shall be in accordance supply availability norm specified by the Commission.

Additional Short-term power procurement

This issue has already been discussed earlier in Chapter-2 of this Approach Paper.

7.1 Distribution Loss Reduction Trajectory for Supply Business

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 un-metered consumption in case of 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 be ascertained only 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, or the actual distribution losses, whichever is lower, shall be considered for setting opening loss levels and loss reduction trajectory for the next Control Period, 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 key efficiency parameter 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 32: 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	11.52%	11.00%	10.75%	10.50%
TPC-D*	2.93%	2.93%	0.61%	0.66%
BEST	11.50%	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.

The actual/revised estimates for Distribution licensees are as under:

Table 20: Actual/ Revised Estimates of Distribution losses for Distribution licensees:

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
MSEDCL	30.20%	24.15%	21.98%	18.20%
RInfra-D	11.25%	11.04%	10.25%	10.25%

	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
TPC-D	2.93%	2.93%	0.67%	0.40%
BEST	11.90%	10.27%	9.29%	9.29%

Distribution loss trajectory for City based distribution licensees

The distribution losses for various city based distribution licensees are tabulated below:

Table 33: 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%
NDPL	27.30%	20.72%	19.75%	18.27%
TPL- Ahmedabad		10.48%	10.43%	10.25%
TPL- Surat		6.01%	6.00%	6.00%

Source: Tariff Orders of respective State Electricity Regulatory Commission, for respective years.

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.

However, determination of distribution loss trajectory will require capital expenditure and other operational strategies to be proposed by Utilities to reduce technical and commercial loss. Hence, it is proposed that the Commission may determine the distribution loss trajectory for the Utilities after considering the Business Plan submitted by the Utilities.

Distribution loss trajectory for State-based distribution licensees

Distribution losses for various State based distribution licensees are tabulated below:

Table 34: Distribution loss comparison for State based distribution licensees

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
Andhra Pradesh	20.02%	18.49%	17.29%	12.84%
Karnataka	21.83%	22.65%	21.74%	20.29%
Gujarat	22.84%	21.47%	20.26%	18.93%

Utility	FY 2006-07	FY 2007-08	FY 2008-09	FY 2009-10
Rajasthan	**34.45%**	**33.40%**	**29.50%**	**24.01%**

Source: Tariff Orders of respective State Electricity Regulatory Commission, for respective years

It may be noted that for inter-Utility comparison for MSEDCL, the values for the individual DISCOMs in other comparable States have been aggregated to provide comparable values, since MSEDCL supplies electricity to the entire State of Maharashtra, excluding Mumbai licence area.

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, the Commission 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 compute the distribution losses accurately.

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%. **However, determination of distribution loss trajectory will require capital expenditure and other operational strategies to be proposed by Utilities to reduce technical and commercial loss. Hence, it is proposed that the Commission may determine the distribution loss trajectory for MSEDCL after considering the Business Plan submitted by MSEDCL.**

7.2 Operation & Maintenance Expenses Norm for Supply Business

Benchmarking and derivation of O&M expenses norms has been discussed in detail in Chapter-6. Hence, based on the allocation matrix proposed earlier in Chapter-6, the O&M expenses pertaining to supply business, has been derived

Particulars	**Wires Business (%)**	**Supply Business (%)**
Employee Expenses	60%	40%
A&G Expenses	50%	50%
R&M	90%	10%

7.2.1 Composite O&M expenses Norm for Supply Business in Maharashtra

The composite O&M norms for Utilities in Maharashtra are as under:

A) Distribution Business

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales (Paise/kWh)	22	20	20	20	22
For Consumers (Rs Lakh/'000 Consumer)	11	18	18	NA	11
For GFA (% of Opening GFA)	4.50%	4.50%	4.50%	1.50%	4.50%

B) Supply Business

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales in Supply Business (Paise/kWh)	9	8	8	9	9
For Consumers in Supply Business (Rs Lakh/'000 Consumer)	5	8	8	NA	5
For GFA of Supply Business (% of Opening GFA)	0.45%	0.45%	0.45%	0.15%	0.45%

However, in order to account for efficiency improvement as indicated by variance in O&M expenses as compared to median value of Other Utilities based on inter-State comparison, O&M expense reduction for Supply Business in the second Control Period is proposed as under:

a) RInfra-D and BEST: 4 paise per unit of sales, spread over five years.

b) MSEDCL: 5 paise per unit of sales, spread over five years.

Hence, for the second Control Period, the Norms would be as tabulated below.

FY 2011-12

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales in Supply Business (Paise/kWh)	8	7	7	9	8
For Consumers in Supply Business (Rs Lakh/'000 Consumer)	4.6	8.0	8.0	NA	4.6
For GFA of Supply Business (% of Opening GFA)	0.45%	0.45%	0.45%	0.15%	0.45%

FY 2012-13

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales in Supply Business (Paise/kWh)	7	6	6	9	7
For Consumers in Supply Business (Rs Lakh/'000 Consumer)	4.88	8.44	8.44	NA	4.88
For GFA of Supply Business (% of Opening GFA)	0.45%	0.45%	0.45%	0.15%	0.45%

FY 2013-14

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales in Supply Business (Paise/kWh)	6	5	5	10	6
For Consumers in Supply Business (Rs Lakh/'000 Consumer)	5.2	8.9	8.9	NA	5.2
For GFA of Supply Business (% of Opening GFA)	0.45%	0.45%	0.45%	0.15%	0.45%

FY 2014-15

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales in Supply Business (Paise/kWh)	6	5	5	10	6
For Consumers in Supply Business (Rs Lakh/'000 Consumer)	5.5	9.4	9.4	NA	5.5
For GFA of Supply Business (% of Opening GFA)	0.45%	0.45%	0.45%	0.15%	0.45%

FY 2015-16

O&M Charges	MSEDCL	RInfra-D	BEST	TPC-D	MPECS
For Sales in Supply Business (Paise/kWh)	5	5	5	11	5
For Consumers in Supply Business (Rs Lakh/'000 Consumer)	5.8	10.0	10.0	NA	5.8
For GFA of Supply Business (% of Opening GFA)	0.45%	0.45%	0.45%	0.15%	0.45%

7.3 Tariff for Wires and Supply Business

As discussed in Chapter-6, with the introduction of competition in distribution business, tariff structuring should also act as enabler for the consumer to benefit from competition. Hence, it is proposed to bifurcate Energy charge for Utilities, viz., “Wheeling Charge” and “Supply Charge”.

7.4 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, worked out to be negative, in view of the high prices of marginal power purchase.

7.5 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 Charge' and would be passed through to the consumers on a six monthly basis, subject to prudence check, since, the proposed mechanism of 'Z–factor Charge' is envisaged to be passed-through on a half yearly basis. Hence, the prevailing mechanism of capping FAC to 10 percent of the variable component, is not required under Z-factor Charge. Moreover, it may also be noted that presently there is no cap on FAC charged from Generating Company to Distribution Company. Even if cap of 10% is imposed on FAC charged by Generating Company to Distribution Companies in Maharashtra, Central Generating Company will not come under the ambit of this Regulation and will continue to pass-through the fuel cost variation to the distribution company. Hence, it is proposed to remove FAC cap of 10% on variable component. Distribution Licensee may get the 'Z-factor Charge' approved from the Commission on half-yearly basis before passing on the same to the consumers.

7.6 Retail Supply Tariff Determination

Tariff for retail supply business of the Distribution Licensee shall be determined by the Commission on the basis of an Application for determination of tariff made by the Distribution Licensee in accordance with the MYT Regulations.

To promote competition, it is felt that the Distribution Licensee may be allowed to offer a rebate to the consumers on tariff and charges determined by the Commission. However, the Distribution licensee offering rebates will have to bear the impact of these rebates entirely and impact of such rebate shall not be allowed to be passed through to the consumers in any form.

It is also proposed that the Distribution licensee shall submit details of such rebates to the Commission every quarter, in the manner and format, as stipulated by the Commission from time to time. Further, such rebates should not be offered selectively to any consumer/s, and will have to be offered to the entire consumer category/sub-category/consumption slab in a non-discriminatory manner.