GUJARAT ELECTRICITY REGULATORY COMMISSION

EXPLANATORY MEMORANDUM

ON

DRAFT GUJARAT ELECTRICITY REGULATORY COMMISSION (MULTI YEAR TARIFF) REGULATIONS, 2023

September 2023

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AIVPL	AspenPark Infra Vadodara Private Limited
A&G	Administrative and General
AAD	Advance Against Depreciation
ARR	Aggregate Revenue Requirement
AT&C Losses	Aggregate Technical and Commercial Losses
BAU	Business As Usual
CAPM	Capital Asset Pricing Model
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CFBC	Circulating Fluid Bed Combustion
COD	Date of Commercial Operation
CPI	Consumer Price Index
DGVCL	Dakshin Gujarat Vij Company Limited
DPA	Deendayal Port Authority
DPR	Detailed Project Report
DSM	Demand Side Management
DTA	Domestic Tariff Area
EA 2003	Electricity Act 2003
ECR	Energy Charge Rate
EE	Energy Efficiency
EPS	Electric Power Survey
FERV	Foreign Exchange Rate Variation
FOR	Forum of Regulators
FPPPA	Fuel and Power Purchase Price Adjustment
FRL	Full Reservoir Level
FY	Financial Year
GCV	Gross Calorific Value
GERC	Gujarat Electricity Regulatory Commission (or the Commission)
GETCO	Gujarat Energy Transmission Company Limited
GFA	Gross Fixed Asset
GIS	Gas Insulated Sub-station
GIFT-PCL	GIFT Power Company Limited
GOI	Government of India
GSECL	Gujarat State Electricity Corporation Limited
GTO	Gate Turn-off Thyristor
GUVNL	Gujarat Urja Vikas Nigam Limited
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IC	Installed Capacity
IDC	Interest During Construction
IGBT	Insulated-Gate Bipolar Transistor
IoWC	Interest on Working Capital
kcal	kilo calorie

kWh	kilo Watt hour
LD	Liquidated Damages
LT-DRAP	Long-term Discom Resource Adequacy Plan
MCLR	Marginal Cost of Funds based Lending Rate
MDDL	Minimum Draw Down Level
MERC	Maharashtra Electricity Regulatory Commission
MGVCL	Madhya Gujarat Vij Company Limited
MoP	Ministry of Power
MTOA	Medium Term Open Access
MUL	MPSEZ Utilities Limited
MVA	Mega Volt Ampere
MW	Mega Watt
MYT	Multi-Year Tariff
NAPAF	Normative Annual Plant Availability Factor
NAPLF	Normative Annual Plant Load Factor
NFA	Net Fixed Asset
NTP	National Tariff Policy
O&M	Operation and Maintenance
PEUM	Partial End Use Method
PGVCL	Paschim Gujarat Vij Company Limited
PSERC	Punjab State Electricity Regulatory Commission
R&M	Renovation and Modernization
RDSS	Revamped Distribution Sector Scheme
RERC	Rajasthan Electricity Regulatory Commission
RLNG	Re-gasified Liquefied Natural Gas
RoCE	Return on Capital Employed
RoE	Return on Equity
RPO	Renewable Purchase Obligation
SBBR	State Bank Base Rate
SFC	Secondary Fuel Consumption
SEZ	Special Economic Zone
SERC	State Electricity Regulatory Commission
SLDC	State Load Dispatch Centre
SLM	Straight Line Method
STU	State Transmission Utility
STATCOM	Static Synchronous Compensator
TPL	Torrent Power Limited
TPL-G	Torrent Power Limited – Generation
TPS	Thermal Power Station
TSC	Transmission Service Charges
UGVCL	Uttar Gujarat Vij Company Limited
WAROI	Weighted Average Rate of Interest
WACC	Weighted Average Capital Cost
WPI	Wholesale Price Index

1 INTRODUCTION

1.1 Policy, Statutory and Regulatory Framework

1.1.1 The Gujarat Electricity Regulatory Commission (hereinafter referred to as 'GERC' or 'the Commission') was constituted on 12th November, 1998 under the erstwhile Electricity Regulatory Commissions Act (ERC), 1998 to discharge the duties and perform the functions specified under the provisions of the erstwhile ERC Act, 1998. Upon enactment of the Electricity Act, 2003 (hereinafter referred to as 'EA 2003' or 'the Act'), GERC was deemed to be constituted under the Act. The Commission has been vested with the functions of regulating the tariff of the generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State under Section 86 (1) (a) of the Act.

1.1.2 Section 61 of the Act provides the guiding principles for the Commission while specifying the terms and conditions for the determination of tariff as under:

> *"61. The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:-*
>
> *(a) The principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;*
>
> *(b) The generation, transmission, distribution and supply of electricity are conducted on commercial principles;*
>
> ***(c) The factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;***
>
> ***(d) Safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;***
>
> *(e) The principles rewarding efficiency in performance;*
>
> *(f) Multi year tariff principles;*
>
> *(g) That the tariff progressively reflects the cost of supply of electricity and also reduces cross-subsidies in the manner specified by the Appropriate Commission;*
>
> *(h) The promotion of co-generation and generation of electricity from renewable sources of energy;*
>
> *(i) The National Electricity Policy and tariff policy"*
>
> **[Emphasis Added]**

1.1.3 **Therefore, the Act mandates the Commission to balance the interest of all the stakeholders and also sector as a whole, by encouraging competition, efficiency, economic use of resources and also safeguarding consumers' interest.**

1.1.4 Section 181(2)(zd) of the Act further empowers the Commission to make regulations on the terms and conditions for the determination of tariff under Section 61 of the Act.

1.1.5 Also, the Ministry of Power (MoP) has notified the National Electricity Policy and the Tariff Policy which provides guidelines for determination of tariff and Annual Revenue Requirement (ARR). The National Electricity Policy provides certain guidelines as regards performance norms and also stipulates the need to provide incentives and disincentives, as reproduced below:

> "*5.8.5 All efforts will have to be made to improve the efficiency of operations in all the segments of the industry. Suitable performance norms of operations together with incentives and disincentives will need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. This will ensure protection of consumers' interests on the one hand and provide motivation for improving the efficiency of operations on the other".*

1.1.6 The Tariff Policy notified on January 28, 2016 stipulates as under:

> *"5.11 Tariff policy lays down the following framework for performance based cost of service regulation in respect of aspects common to generation, transmission as well as distribution…*
>
> *…*
>
> ***h) Multi Year Tariff***
>
> *1) Section 61 of the Act states that the Appropriate Commission for determining the terms and conditions for the determination of tariff shall be guided, inter-alia, by Multi-Year Tariff (MYT) principles. 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…"*

1.1.7 The EA 2003, as amended from time to time, requires the Appropriate Commission to be guided by Multi-Year Tariff (MYT) principles and the principles and methodologies specified by the Central Electricity Regulatory Commission (here after referred to as 'CERC' or 'the Central Commission') for determination of the tariff applicable to

Generating Companies and Transmission Licensees, while specifying the Terms and Conditions for determination of tariff. The latest available tariff regulations as notified by the CERC are the CERC (Terms and Conditions of Tariff) Regulations, 2019, applicable for the Tariff Period from April 01, 2019 to March 31, 2024. The Commission in accordance with EA 2003 has been guided by the principles and methodologies specified by the CERC for determination of the tariff applicable to Generating Companies and Transmission Licensees. The Commission has adopted certain principles and methodologies specified in the CERC Tariff Regulations, 2019 with appropriate modifications.

1.1.8 Further, as per the Section 62 of the Act, the Commission has to determine the tariff for the Generating Companies, Distribution Licensees, Transmission licensees, wheeling and retail sale of electricity and the Utilities needs to comply with the procedure laid down by the Commission for determination of the Tariff for computing the revenue. The relevant extract of Section 62 of the Electricity Act is shown below:

"Section 62. (Determination of tariff): --- (1) The Appropriate Commission shall determine the tariff in accordance with the provisions of this Act for –

(a) supply of electricity by a generating company to a distribution licensee:

Provided that the Appropriate Commission may, in case of shortage of supply of electricity, fix the minimum and maximum ceiling of tariff for sale or purchase of electricity in pursuance of an agreement, entered into between a generating company and a licensee or between licensees, for a period not exceeding one year to ensure reasonable prices of electricity;

(b) transmission of electricity;

(c) wheeling of electricity;

(d) retail sale of electricity:

Provided that in case of distribution of electricity in the same area by two or more distribution licensees, the Appropriate Commission may, for promoting competition among distribution licensees, fix only maximum ceiling of tariff for retail sale of electricity.

(2) The Appropriate Commission may require a licensee or a generating company to fu rnish separate details, as may be specified in respect of generation, transmission and distribution for determination of tariff.

(3) The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate

according to the consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required.

(4) No tariff or part of any tariff may ordinarily be amended, more frequently than once in any financial year, except in respect of any changes expressly permitted under the terms of any fuel surcharge formula as may be specified.

(5) The Commission may require a licensee or a generating company to comply with such procedures as may be specified for calculating the expected revenues from the tariff and charges which he or it is permitted to recover.

(6) If any licensee or a generating company recovers a price or charge exceeding the tariff determined under this section, the excess amount shall be recoverable by the person who has paid such price or charge along with interest equivalent to the bank rate without prejudice to any other liability incurred by the licensee."

1.1.9 The existing GERC Multi-Year Tariff (MYT) Regulations, i.e., the GERC MYT Regulations, 2016 were notified on March 28, 2016 for a five-year Control Period commencing from April 1, 2016 to March 31, 2021. Subsequently, the Commission amended these Regulations vide the GERC MYT (First Amendment) Regulations, 2016 dated December 2, 2016 and the GERC MYT (Second Amendment) Regulations, 2018 dated August 18, 2018. Further, the applicability of the GERC MYT Regulations, 2016 was extended thrice (one year at a time) for three years, i.e., till March 31, 2024. As the applicability of the existing GERC MYT Regulations 2016 is coming to end on March 31, 2024, the Commission proposes to specify the terms and conditions of tariff for the next Control Period, i.e., the GERC MYT Regulations 2023. The next Control Period is for five years, i.e., from FY 2024-25 to FY 2028-28.

1.2 Discussion Paper for MYT Regulations

1.2.1 The Staff of the Commission initiated the process of framing tariff regulations for the 2024-29 period by issuing Discussion Paper on Multi-Year Tariff Regulations for the Fourth Control Period in the month of June 2023 (hereinafter referred to as the Discussion Paper) and solicited comments of stakeholders on various options for regulatory framework to be considered while framing the new Multi-Year Tariff Regulations for the Control Period 2024-29. The Discussion Paper was issued to initiate discussions on the changes required, if any, on the existing tariff norms keeping in view the developments in the sector during the ongoing tariff period, current and perceived challenges in the power sector and duly recognizing the need for sustainable market development based on the experiences of the past years of tariff regulation notified by the Commission. The Discussion Paper was aimed at soliciting preliminary views of the stakeholders on different aspects of tariff setting during the Control Period 2024-29.

1.2.2 Various stakeholders including State sector utilities, private sector utilities, Industry Association and other organizations commented on the Consultation Paper.

1.2.3 While preparing the Draft Tariff Regulations for 2019-24, the Commission has taken a holistic view of a) the existing economic environment of the power sector in the State; b) issues raised in the Discussion Paper and comments thereon; c) issues otherwise raised by the stakeholders; and a) the last ten year's performance of the power utilities in the State.

1.2.4 For preparation of the draft GERC MYT Regulations 2023, the Commission has taken into cognizance of the Electricity Act, National Electricity Policy, Tariff Policy and recommendations of Forum of Regulators (FOR). The Commission has also analyzed the challenges faced in approval of tariff by themselves and also other ERCs (Electricity Regulatory Commissions) and data gaps that were sought frequently during the tariff proceedings. Further, the Commission has also taken a holistic view of a) the existing economic environment of the power sector in the State; b) issues raised in the Discussion Paper and comments thereon; c) issues otherwise raised by the stakeholders; and a) the last ten year's performance of the power utilities in the State.

1.2.5 In the subsequent sections of this Explanatory Memorandum, the Commission has elaborated on the changes proposed in the draft GERC MYT Regulations, 2023 w.r.t existing GERC MYT Regulations, 2016 (as amended from time to time). Generally, only the clauses/provisions where any addition/modification is proposed in the draft GERC MYT Regulations, 2023 have been discussed in this Explanatory Memorandum. However, in certain cases, where an entirely new clause or concept is proposed, the rationale of introducing the same is discussed. Further, in cases where no change is proposed, the same has not been explicitly mentioned. This Explanatory memorandum is prepared in the sequential order considering the chronology of the provisions/clauses proposed in the draft GERC MYT Regulations, 2023.

2 PRELIMINARY

This Chapter elaborates the proposed amendments in the Preliminary chapter of the GERC MYT Regulations, 2016 and explain reasons for the amendments.

2.1 Short title, extent, applicability and commencement

The Commission has proposed to continue with the Multi-Year Tariff (MYT) framework with Control Period having duration of 5 years. The draft GERC MYT Regulations, 2023 shall be applicable from April 01, 2024 to March 31, 2029.

2.2 Definitions

The Commission has modified few definitions and also added some new definitions for bringing clarity on various provisions/regulations/clauses proposed in the draft GERC MYT Regulations, 2023. These modifications/additions are elaborated as follows:

2.2.1 Accounting Statement

The Companies Act, 2013 came into force with effect from September 21, 2013. Accordingly, the schedule related to Financial Statement of the companies has been modified. Also, the Ministry of Corporate Affairs (MCA) has notified Indian Accounting Standards (IND AS) which mandates the companies to shift from Generally Accepted Accounting Principles (GAAP) to IND AS for preparation of financial statement. The Ministry of Corporate Affairs (MCA) issued a note dated January 2, 2015, outlining phases in which IND AS converged with International Financial Reporting Standards (IFRS) has to be implemented in India, for Companies other than banking, insurance and Non-Bank Financial Companies (NBFCs).

Considering the difference in principles of preparation and reporting of financial statement with the preparation of ARR which follows historical accounting approach, there is a need for reconciliation of ARR formats with the financial statement prepared under IND AS. Accordingly, the existing Accounting Statement definition needs to be amended to address the issue of implementation of IND AS, as well as transition from GAAP to IND AS. In view of the above, the Commission proposes to amend the Accounting Statement definition as mentioned below:

"(1) ***"Accounting Statement"*** *means for each financial year, the following statements, namely*:

(a) balance sheet, prepared in accordance with the format prescribed by the Commission from time to time, with reference to each licensed or regulated business separately, duly certified by the statutory auditors;

(b) profit and loss account, prepared in accordance with the format prescribed by the Commission from time to time, with reference to each licensed or regulated business separately, duly certified by the statutory auditors;

(c) cash flow statement, prepared in accordance with the format prescribed by the Commission from time to time, with reference to each licensed or regulated business separately, duly certified by the statutory auditors;

(d) balance sheet, prepared in accordance with the form contained in Part I of Schedule III to the Companies Act, 2013, as amended from time to time, whichever is applicable;

(e) profit and loss account, complying with the requirements contained in Part II of Schedule III to the Companies Act, 2013, as amended from time to time, whichever is applicable;

(f) cash flow statement, prepared in accordance with the applicable Accounting Standard of the Institute of Chartered Accountants of India (ICAI), and as per Section 2(40) of the Companies Act 2013, as amended from time to time;

(g) report of the statutory auditors;

(h) reconciliation statement, duly certified by the statutory auditors, showing the reconciliation between the total expenses, revenue, assets and liabilities, of the entity as a Company and the expenses, revenue, assets and liabilities, separately for each business regulated by the Commission and unregulated business operations, wherever applicable;

(i) cost records prescribed by the Central Government under Section 148 of Companies Act, 2013 along with Cost Audit Reports; together with notes thereto, and such other supporting statements and information as the Commission may direct from time to time:

Provided that in case of any local authority engaged in the business of distribution of electricity, the Accounting Statement shall mean the items, as mentioned above, prepared and maintained in accordance with the relevant Acts or Statutes as applicable to such local authority;"

2.2.2 Additional Capital Expenditure and Additional Capitalisation

The Commission has added definitions of additional Capital expenditure and additional capitalization in the draft Regulations for providing greater clarity, as mentioned below:

"*(3) "Additional Capital Expenditure" means the capital expenditure incurred or projected to be incurred, after the date of commercial operation of the project by the Generating Company or Transmission Licensee or SLDC or Distribution licensee, as the case may be, in accordance with the provisions* *of these Regulations;*

(4) "Additional Capitalisation" means the additional capital expenditure admitted by the Commission after prudence check, in accordance with these Regulations;"

2.2.3 Allocation Statement

The actual expenses incurred by the Applicant under the regulated business based on audited accounts are allowed by the Commission for recovery through tariff after prudent check. However, where separate accounts of the Applicant are not available, the Commission allows expenses based on the allocation statement of the Applicant. In the draft GERC MYT Regulations, 2023 it has been proposed that the Applicant needs to maintain separate accounting statement for the regulated business and for other businesses. Therefore, the following proviso is proposed to be included under the definition of allocation statement:

"Provided that 'Allocation' Statement' shall not be construed as a substitute for maintaining separate accounting statement for the regulated business and other businesses of the regulated Utilities."

2.2.4 Auditor

The Commission has added the definition of the 'Auditor' in accordance with the proviso related to Companies Act 2013 and also in line with the CERC Tariff Regulations 2019, as shown below:

*"(10) **"Auditor"** means an auditor appointed by an applicant, in accordance with Section 139 0f Chapter X of the Companies Act, 2013 (18 of 2013) or any other law for the time being in force;"*

2.2.5 Auxiliary Energy Consumption

In the first amendment, to CERC Tariff Regulations, 2019-24 on 25th August 2020, CERC has added some definitions, clauses related to Supplementary Capacity Charges, interest on loan, return on equity, working capital requirement, Supplementary Energy Charges, etc., all related to installation of emission control systems by the Generating Company. As this Amendment is relevant for the State of Gujarat also, the Commission proposes to incorporate the relevant amendment clauses at the appropriate places in the GERC MYT Regulations, 2023. Addition of definition for Auxiliary Energy Consumption is added as Regulation 2 (12) below:

*"(12) **"Auxiliary energy consumption for emission control system"** or **"AUXen"** in relation to a period in case of coal or lignite based thermal generating station*

means the quantum of energy consumed by auxiliary equipment of the emission control system of the coal or lignite based thermal generating station in addition to the auxiliary energy consumption under Clause (11) of this Regulation;"

2.2.6 Availability

The Commission has updated the definition of Availability as reproduced below:

"(13) ***"Availability"***

(a) in relation to a thermal generating station/unit for any period means the average of the daily average declared capacities as certified by SLDC for all the days during that period expressed as a percentage of the installed capacity of the generating station/unit minus the normative auxiliary consumption in MW as specified in these Regulations, and shall be computed in accordance with the following formula:

$$Availability = 10000 \times \sum_{i=1}^{N} DC_i / \{ N \times IC \times (100 - AUX_n - \mathrm{AUX_{en}}) \} \%$$

Where,

N = number of days in the given period;

DC = Average Declared Capacity in MW for the i^{th} day in such period;

IC = Installed Capacity of the generating station in MW;

AUX_n = Normative Auxiliary Consumption in MW, expressed as a percentage of gross generation;

$\mathrm{AUX_{en}}$ = Normative Auxiliary Consumption for Emission Control System in MW, expressed as a percentage of gross generation:

(b) in relation to a transmission system for a given period means the time in hours during that period the transmission system is capable of transmitting electricity at its rated voltage expressed in percentage of total hours in the given period and shall be calculated as provided in Annexure II to these Regulations;"

2.2.7 Beneficiary

In GERC MYT Regulations, 2016, 'Beneficiary' for Generating Station has been defined. However, under electricity sector, for every function related to Generation, Transmission and Distribution, there is a user, who is an actual beneficiary. Therefore, for greater clarity and to minimise ambiguity, the definition of beneficiary is amended to include other beneficiaries also, as shown below:

"(15) ***"Beneficiary"*** *shall mean:*

a) in relation to a Generating Station, the purchaser of electricity generated at such Station whose Tariff is determined under these Regulations;

b) in relation to a Transmission Licensee, the Transmission System Users;

c) in relation to the Distribution Wires Business, the Generating Companies connected to the distribution system and consumers;

d) in relation to the Retail Supply Business, the consumers;

e) in relation to the SLDC, the Distribution Licensees and Open Access consumers who utilise the Intra-State Transmission system for transmission of electricity and / or utilise the distribution system of a Licensee in the State for wheeling of electricity and / or avail the services of the SLDC relating to scheduling and real-time grid operations, State energy accounting, operation of pool account, etc.;"

2.2.8 **Change in Law**

Regulation 2(18) of the GERC MYT Regulations, 2016 provides the definition for the Change in Law. However, the existing definition does not include any provision for the change in taxes and duties. Under Section 107 of EA 2003 and in pursuant to Tariff Policy 2016, the Ministry of Power vide letter dated August 27, 2018, has issued directions to the CERC for allowing any change in domestic duties, levies, cess and taxes imposed by the Government leading to changes in cost, to be allowed as pass through under Change in Law. Further, there are several Orders of CERC and Judgements of APTEL ruling that change in tax rates are considered under Change in Law. With respect to O&M expenses, the Commission in these draft Regulations has proposed that the same will be allowed based on the inflation factor i.e. Wholesale Price Index (WPI) and Consumer Price Index of Industrial Workers (CPIIW), whereby the Commission is of the view that components of WPI takes care of any price variation due to change in any tax as well. Since, the escalation allowed on the O&M Expenses is based on inflation factor and accordingly, any additional claim of change in taxes and duties would amount to double allowance. Hence, the Commission has proposed to exclude the change in taxes and duties from the 'Change in Law'. Accordingly, the Commission has added the following proviso in the draft Regulations, as under:

"(f) any change in taxes or duties, or introduction of any taxes or duties levied by the Central or any State Government excluding the change in taxes and duties related to O&M expenses:

Provided that financial implication of change in law in relation to a Power Purchase Agreement (PPA) or Transmission Service Agreement (TSA) shall be in line with the provisions of PPA or TSA;"

2.2.9 **Charges**

The GERC MYT Regulations, 2016 does not define charges. Therefore, for greater clarity, the charges have been defined in the draft Regulations as provided below:

*"(19) "**Charges**" means payments to be collected by the Generating Company or Licensee or SLDC for the services rendered by it;"*

2.2.10 **Competitive Bidding**

The Commission has proposed to include the definition of "Competitive Bidding", in line with the definition specified in the CERC Tariff Regulations, 2019, as reproduced below:

*"(21) "**Competitive Bidding**" means a transparent process for procurement of power, equipment, services and works in which bids are invited by the procurer by open advertisement covering the scope and specifications of the power requirement, equipment, services and works required, and the terms and conditions of the proposed contract as well as the criteria by which bids shall be evaluated, and shall include domestic competitive bidding and international competitive bidding;"*

2.2.11 **Control Period**

The Control Period refers to fixed period typically ranging from 3 to 5 years during which the principles for determination of Aggregate Revenue Requirement (ARR) and tariff specified in these Regulations shall remain valid. In the GERC MYT Regulations, 2016, the Control Period was defined as five-years, which was subsequently extended by three more years, one year at a time. The EA 2003 stipulates that a Multi-Year Tariff (MYT) framework has to be specified for determination of ARR and Tariffs. The Tariff Policy has stipulated a five-year MYT framework, after the initial Control Period. The CERC has also notified the CERC Tariff Regulations, 2019 on March 7, 2019 for the Control Period of five-years from April 1, 2019 to March 31, 2024. Accordingly, the Commission has proposed to continue with a five-year MYT framework for the next Control Period as well, i.e., the Fourth Control Period. A five-year Control Period would give clarity on the ARR and tariff determination process for a longer tenure, thereby providing a corresponding amount of regulatory certainty to the process. As the next Control Period will be starting from April 1, 2024 to March 31, 2029, the Commission has accordingly amended the existing definition of Control Period as reproduced below:

*"(22) "**Control Period**" means the period of five years from April 01, 2024 to March 31, 2029, for submission of forecast in accordance with **Chapter 2** of these Regulations;"*

2.2.12 **Contracted Capacity**

The definition of the contracted capacity is proposed to be included in these Regulations for more clarity, which is reproduced as below:

*"(23) "**Contracted Capacity**" means the capacity in MW contracted by a long-term Transmission System User as part of its long-term power procurement plan through a power purchase agreement or arrangement, and shall be equivalent to the deemed Transmission Capacity Right of a Transmission System User;"*

2.2.13 **Cut-Off Date**

CERC in its Tariff Regulations, 2019 has amended the definition of Cut-off date in order to provide a uniform period to all the projects, i.e., to allow a period of thirty-six calendar months (three years) to all projects from the last day of the month in which the project is commissioned. The Commission also feels that such provision is required to be incorporated so as to provide uniformity to all the projects. Hence, the definition of the Cut-off date is proposed to be in line with the CERC Tariff Regulations, 2019, which is reproduced as below:

*"(24) "**Cut-off Date**" means the last day of the calendar month after thirty six months from the date of commercial operation of the project ;"*

2.2.14 **De-capitalisation**

The definition of De-capitalisation has been amended in GERC MYT Regulation, 2023 as reproduced below:

***"**(27) **"De-capitalisation"** means reduction in Gross Fixed Assets of the project corresponding to the removal of assets as admitted by the Commission corresponding to inter-unit transfer of assets or the assets taken out from service;"*

2.2.15 **Deemed Distribution Licensee, Distribution Licensee and Distribution System User**

The definitions of the Deemed Distribution Licensee, Distribution Licensee and Distribution system user has been included in the GERC MYT Regulations, 2023 as reproduced below:

"*(29) "**Deemed Distribution Licensee**" means a person deemed to be a Distribution Licensee under Section 14 of the Act;"*

*"(32) **"Distribution Licensee"** means a Licensee authorised to operate and maintain a distribution system for supplying electricity to consumers in its area of supply;*

*(33) **"Distribution System User"** means a retail consumers of the Distribution licensee to whom the electricity is supplied by the Distribution licensee through their own distribution infrastructure along with the person who has been allowed open access to the distribution system of a distribution licensee and the consumer or a class of consumers allowed to receive supply from a person other than a distribution licensee;"*

2.2.16 **Detailed Project Report Scheme**

In the draft GERC MYT Regulations, 2023, the Commission has proposed that the capital expenditure will be allowed in accordance with the "Guidelines for Capital Expenditure Approval Framework". As per the said guidelines, an Applicant is required to submit detailed project report for various schemes. Accordingly, for greater clarity and to minimise ambiguity the definition of the Detailed Project Report Scheme is added in the draft Regulations, as reproduced below:

*"(35) "**Detailed Project Report Scheme**" (or "DPR Scheme") means a capital expenditure Scheme with projected capital cost exceeding the limits specified in the '*Guidelines for Capital Expenditure Approval Framework*' as provided in Annexure III to these Regulations, for in-principle clearance of proposed Investment schemes or any such amount stipulated by the Commission, for which the Generating Company or Transmission Licensee or SLDC or Distribution licensee, as the case may be, is required to obtain prior in-principle approval by submitting a Detailed Project Report (DPR) in accordance with above said framework;"*

2.2.17 **Emission Control System:**

As mentioned in 2.2.5, in line with Amendment to CERC Tariff Regulations definition for Emission Control System is added as Regulation 2 (16), same is reproduced below:

"(36) "Emission Control System" means a set of equipment or devices required to be installed in coal or lignite based thermal generating station or unit thereof to meet the revised emission standards;"

2.2.18 **Element, Expansion project, Expected Revenue from Tariff and Charges and Extended Life**

The definitions of 'Element', 'Expansion project' and 'Extended life' were not provided in the GERC MYT Regulations, 2016. The Commission has defined these terms in the draft Regulations in accordance with the CERC Tariff Regulations, 2019, and modified the 'Expected Revenue from Tariff and Charges definition' as under:

*"(37) **"Element"** means an asset which has been distinctively defined under the scope of the transmission project in the investment Approval such as transmission lines including line bays and line reactors, substations, bays, compensation device, Interconnecting Transformers, etc.;*

*(38) "**Expected Revenue from Tariff and Charges**" means the revenue estimated to accrue to Generating Company or Transmission Licensee or SLDC or Distribution Licensee from the Regulated Business at the prevailing tariffs **and charges**;*

….

*(41) **"Expansion project"** shall include any addition of new capacity to the existing Generating station or augmentation of the Transmission system, as the case may be;*

*(42) **"Extended Life"** means the life of a Generating Station or Unit thereof or of a Transmission system or element thereof or Distribution system or element thereof, beyond the period of Useful Life, as may be approved by the Commission on a case to case basis;"*

2.2.19 **Fees**

The definition of 'Fees' has been updated in the draft GERC MYT Regulations, 2023 to provide more clarity as reproduced below:

*"(43) **"Fees"** means payments to be collected by the SLDC for services rendered on account of registration, membership or any other account as determined by the Commission;"*

2.2.20 **Financial Year**

Financial Year was not defined in GERC MYT Regulation 2016 and the definition has been added in the draft GERC MYT Regulations, 2023 as under:

*"(44) **"Financial Year"** means a period commencing on 1st April of a calendar year and ending on 31st March of the subsequent calendar year;"*

2.2.21 **Force Majeure Event**

As per the Ministry of Finance ("MOF") office memorandum dated February 19, 2020, it is clarified that the disruption of supply chains due to the spread of COVID-19 would be considered as a Force Majeure event covered by related clause (as a case of natural calamity). And, with respect to procurement contracts of the Government (for goods and services), Force Majeure may be invoked as per the procedure prescribed in the Manual for Procurement of Goods, 2017. In view of the Covid-19 outbreak, the Commission has proposed for consideration of such pandemic events under force majeure and has included the same in the definition.

*"(45) **"Force Majeure Event"***

….

> *(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises,* ***pandemic,*** *or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or*
>
> *….."*

Also, the delay in obtaining statutory approval for the project non-attributable to the developer is proposed to be included under force majeure event. Therefore, the following proviso is proposed to be included in the draft Regulations, as under:

> *"(d) Delay in obtaining statutory approval for the project except where the delay is attributable to project developer;"*

2.2.22 **Fuel Supply Agreement**

The Commission in the draft GERC MYT Regulations, 2023, has proposed that the Generating companies shall require to submit the Fuel Utilization Plan. The Fuel Utilization Plan is usually linked to availability of fuel as specified in the Fuel Supply Agreement. Accordingly, the definition of Fuel Supply Agreement is proposed to be included in the draft Regulations for greater clarity, as under:

*"(46) "**Fuel Supply Agreement"** means the agreement executed between the Generating Company and the fuel supplier for supply of fuel to the Generating Station for generation and supply of electricity to the beneficiaries;"*

2.2.23 **Generating Company**

The definition of Generating Company was not provided in the GERC MYT Regulations, 2016. The Commission in the draft GERC MYT Regulations, 2023 has added the same for greater clarity, as reproduced below:

*"(48) **"Generating Company"** means any company or body corporate or association or body of individuals, whether incorporated or not, or artificial juridical person, which owns or operates or maintains a Generating Station;"*

2.2.24 **Generating Unit**

GERC MYT Regulations 2016 did not include a few generator types hence the definition has been updated to provide additional clarity as under:

*“(50)“**Generating Unit**” in relation to a thermal generating station (other than combined cycle thermal generating station) means steam generator, turbine-generator and auxiliaries, or in relation to a combined cycle thermal generating station, means turbine-generator and auxiliaries or combustion turbine-generator, associated waste heat recovery boiler, connected steam turbine- generator and auxiliaries; and in relation to a hydro generating station means turbine generator and its auxiliaries;”*

2.2.25 **Intra-State Transmission System (or "InSTS”)**

In the GERC MYT Regulations, 2016, the ‘Intra-State Transmission System’ were not defined. The same has been added for greater clarity in the draft Regulations, as reproduced below:

*“(57) **“Intra-State Transmission System” (**or **"InSTS”)** means any system for conveyance of electricity by transmission lines within the area of the State of Gujarat, and includes all transmission lines, sub-stations and associated equipment of Transmission Licensees in the State:*

Provided that the definition of point of separation between a transmission system and distribution system and between a Generating station and Transmission system shall be guided by the Regulations notified by the Central Electricity Authority under clause (b) of Section 73 of the Act;”

2.2.26 **Licensee**

The Commission in the draft GERC MYT Regulation, 2023 has included the definition of the Licensee in line with the provisions of the Electricity Act, 2003 for better clarity purpose:

*“(58) **“Licensee”** for the purpose of these Regulations shall mean a Transmission Licensee or Distribution Licensee, as the case may be, duly authorised by the Commission under Section 14 or exempted under Section 13 of the Act including deemed licensee;”*

2.2.27 **Long Term Power Procurement and Medium-Term Power Procurement**

The Commission in the draft GERC MYT Regulations, 2023 has proposed for submission of Power Procurement Plan for the MYT period with details related to Long/Short /Medium term Power Procurement. Accordingly, the ‘Long-Term Power

Procurement' and 'Medium-Term Power Procurement' are defined in line with the "Guidelines for Determination of Tariff by Bidding Process for Procurement of Power by Distribution Licensees" issued by MoP, as reproduced below:

*"(59) **"Long Term Power Procurement"** means Procurement of power under any arrangement or agreement with a term or duration exceeding seven years but not exceeding twenty-five years;*

…..

*(61) **"Medium Term Power Procurement"** means Procurement of power under any arrangement or agreement with a term or duration exceeding one year but not exceeding seven years;"*

2.2.26. **Non-DPR Scheme**

In the draft GERC MYT Regulations, 2023, it is proposed that the Commission will approve the capital expenditure as per the "Guidelines for Capital Expenditure Approval Framework". Accordingly, there is necessity of defining the Non-Detailed Project Report Scheme as under:

*"(65) **"Non-DPR Scheme"** means a capital expenditure Scheme with projected capital cost within the limits specified in the guidelines for in-principle clearance of proposed Investment schemes or any such amount stipulated by the Commission, for which the Generating Company or Transmission Licensee or SLDC or Distribution licensee, as the case may be, is not required to obtain prior in-principle approval of the Commission;"*

2.2.28 **Non-Pithead Generating Station**

The term 'Non-Pithead Generating Station' was not defined in the GERC MYT Regulations, 2016. The same has been defined in the draft Regulations for greater clarity, as under:

*"(66) "**Non-Pithead generating station"** means a Generating station, which is not covered under Pithead Generating station;"*

2.2.29 **Pithead Generating Station**

The Commission has added the definition for 'Pithead Generating Station' in the draft

GERC MYT Regulations, 2023, as reproduced below:

*"(69) **"Pithead Generating Station"** means a Generating station having captive transportation system for its exclusive use for transportation of coal from the loading point at the mining end up to the unloading point at the Generating*

station without using the normal public transportation system;"

2.2.30 **Plant Availability Factor (PAF)**

The term 'Plant Availability Factor (PAF)' was not defined in the GERC MYT Regulations, 2016. For greater clarity, the same has added the definition of PAF, as reproduced below:

*"(72) **"Plant Availability Factor"** or **"(PAF)"** in relation to a Generating station for any period means the average of the daily declared capacities (DCs) for all the days during the period expressed as a percentage of the installed capacity in MW less the normative auxiliary energy consumption;"*

2.2.31 **Plant Load Factor (PLF)**

The Commission observed that CERC has issued Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (First Amendment) Regulations, 2020 dated 1 April, 2020; wherein it has specified relevant clauses for Auxiliary Energy Consumption (AEC) on account of emission control system of thermal Generating Stations. The Commission has also proposed to adopt the same in the GERC MYT Regulations, 2023. Accordingly, the PLF formula has been proposed to be amended as shown below along with an explanation of AUXen:

"

$$PLF = 10000 \times \sum_{i=1}^{N} SGi / \{ N \times IC \times (100 - AUXn - AUXen) \} \%$$

……

AUXen = Normative Auxiliary Energy Consumption for emission control system as a percentage of gross energy generation, wherever applicable"

2.2.32 **Project**

The Ministry of Environment Forest and Climate Change (MoEFCC) has notified Environment (Protection) Amendment Rules, 2015 wherein, the norms for thermal Generating Stations has been revised. In accordance with the revised norms, the Commission has proposed to amend the definition of 'Project' in accordance with the CERC Tariff Regulations, 2019 as reproduced below:

*"(74) **"Project"** means:*

(a) in case of thermal Generating station, all components of the thermal Generating station and includes pollution control system, effluent treatment plan, as may be required but does not include mining if it is a pit head project and dedicated

captive coal mine;

(b) in case of hydro Generating station, all components of the hydro Generating station and includes dam, intake water conductor system, power Generating station, as apportioned to power generation; and

(c) in case of Transmission, all components and elements of the Transmission system including communication system;"

2.2.33 **Prudence Check**

The Commission has decided to provide more clarity on the definition of 'Prudence Check' and same has been reproduced below:

*"(75) "**Prudence Check**" means scrutiny of reasonableness of any cost or expenditure incurred or proposed to be incurred, financing plan, use of efficient technology, cost and time over-run and such other factors as may be considered appropriate by the Commission for determination of tariff; in accordance with these regulations by the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be;"*

2.2.34 **Rated Voltage**

The Commission has decided to modify the definition of Rated Voltage in the draft GERC MYT Regulations, 2023 in line with CERC MYT Regulations, 2019 as under:

*"(77) **"Rated Voltage"** means the manufacturer's design voltage at which the transmission system is designed to operate and includes such lower voltage at which any transmission line is charged or for the time being charged, in consultation with Transmission System Users;"*

2.2.35 **Revised Emission Standards**

In accordance with the Environment (Protection) Amendment Rules, 2015, the Commission has proposed for defining the 'Revised Emission Standards' in the draft Regulations, as under:

*"(78) **"Revised Emission Standards"** in respect of thermal Generating station means the revised norms notified as per Environment (Protection) Amendment Rules, 2015 or any other Rules as may be notified from time to time;"*

2.2.36 **Short Term Power Procurement**

The Commission has proposed for submission of Power Procurement Plan for the MYT period with details related to Long/Short/Medium-Term Power Procurement. Accordingly, the 'Short Term Power Procurement' is defined in line with the

"Guidelines for Determination of Tariff by Bidding Process for Procurement of Power by Distribution Licensees" issued by MoP, as under:

*"(83) "**Short Term Power Procurement"** means Procurement of power under any arrangement or agreement with a term or duration less than or equal to one year;"*

2.2.37 **Scheduled Energy**

The Commission has added the definition of 'Scheduled Energy' for greater clarity in the draft GERC MYT Regulations, 2023 in accordance with the CERC Tariff Regulations *2019, as reproduced below:*

*"(86) "**Scheduled Energy"** means the quantum of energy scheduled by the concerned Load Despatch Centre to be injected into the grid by a Generating station for a given time period;"*

2.2.38 **Terminal Liabilities**

The Commission has added the definition of 'Terminal Liabilities' for greater clarity in the draft GERC MYT Regulations, 2023, as reproduced below:

*"(88) **"Terminal Liabilities"** means terminal benefits such as Death cim Retirement Gratuity, Ex-gratia, Pension including Family Pension, Commuted Pension, Leave Encashment, LTC, Dearness relief, Interim relief, Medical reimbursement including fixed medical allowance in respect of pensioners, etc.;"*

2.2.39 **Thermal Generating Station**

The Commission has added the definition of 'Thermal Generating Station' in the draft GERC MYT Regulations, 2023 in accordance with the CERC Tariff Regulations, 2019 as reproduced below:

*"(89) **"Thermal Generating Station"** means a Generating Station or a Unit thereof that generates electricity using fossil fuels such as coal, lignite, gas, liquid fuel or combination of these as its primary source of energy;"*

2.2.40 **Transmission System**

The Commission has added the definition of 'Transmission System' in the draft GERC MYT Regulations, 2023 in accordance with the CERC Tariff Regulations, 2019, as reproduced below:

*"(90) **"Transmission System"** means a line or a group of lines with or without associated substation, and includes equipment associated with transmission lines and sub-stations ;"*

2.2.41 **Transmission Capacity Rights and Transmission Licensee**

The Commission has added the definition of ‘Transmission Capacity Rights’ and ‘Transmission Licensee’ in the draft GERC MYT Regulations, 2023 for greater clarity, as under:

“(91) ***“Transmission Capacity Rights”*** *means the right of a Transmission System User to transfer power in MW, under normal circumstances, between such points of injection and drawal as may be set out in the Bulk Power Transmission Agreement;*

(92) "***Transmission Licensee”*** *means a Licensee authorised by the Commission to establish or operate transmission lines under Section 14 of the Act;”*

2.2.42 **Unloading Point**

The Commission has added the definition of ‘Unloading Point in the draft GERC MYT Regulations, 2023 in accordance with the CERC Tariff Regulations, 2019, as reproduced below:

“(94) ***“Unloading Point”*** *means the point within the premises of the coal or lignite based thermal generating station where the coal or lignite is unloaded from the rake or truck or any other mode of transport;”*

2.2.43 **Useful life**

GERC MYT Regulations 2016 did not include the useful life of Communication Systems and same has been added draft GERC MYT Regulations, 2023 in line with CERC MYT Regulations, 2019 as under:

*“(95) “****Useful life”*** *in relation to a unit of a generating station, transmission system and distribution system from the date of commercial operation shall mean the following, namely:*

….

Communication System : 15 years”

2.2.44 **User**

GERC MYT Regulations 2016 did not include the definition of ‘User’ and same has been included as under:

*“(96) “****User****” means a Licensee, a Generating Company, a person who has set up a captive generating plant, or a consumer availing open access, utilizing the transmission system of a transmission Licensee or distribution system of a Distribution Licensee;”*

2.2.45 **Wheeling and Wheeling Business**

The Commission has added the definition of 'Wheeling' and 'Wheeling Business' in the draft GERC MYT Regulations, 2023, as reproduced below:

*"(97) **"Wheeling"** means the operation whereby the distribution system and associated facilities of a Transmission Licensee or Distribution Licensee, as the case may be, are used by another person for the conveyance of electricity on payment of charges to be determined under section 62 of the Act;*

*(98) **"Wheeling Business** means the business of operating and maintaining a distribution system for conveyance of electricity in the area of supply of the distribution licensee;"*

2.2.46 **Year**

The definition provided in GERC MYT Regulations 2016 has been updated to provide more clarity in the draft GERC MYT Regulations, 2023 as under:

*"(99)"**Year**" means financial year ending on 31st March, and*

(a) "Current Year" shall mean the year in which the petition for determination of tariff is required to be filed;

(b) "Previous Year" shall mean the year immediately preceding the current year;

(c) "Ensuing Year" shall mean the year next following the current year;"

2.3 Deviation from norms

2.3.1 CERC, in its Tariff Regulations, 2019, has provided a clause permitting Generating Companies and Transmission Licensees to charge lower than approved tariff which is subjected to mutual agreement between the parties and need to be intimated to the Commission.

2.3.2 Accordingly, in the draft GERC MYT Regulations, 2023, the Commission has proposed to allow the Generating Station for sale of power below the tariff determined by the Commission, with a condition that the differential amount will not be allowed to be recovered in future. Accordingly, the existing Regulations related to 'Deviation from norms' is proposed to be amended as reproduced below:

"5 Deviation from norms

5.1 The tariff determined in these Regulations shall be a ceiling tariff, and Generating Company and its Beneficiaries may mutually agree to charge a lower tariff.

5.2 Generating Company may opt to charge a lower tariff for a period not exceeding the validity of these Regulations on agreeing to deviation from operational parameters, reduction in Operation and Maintenance expenses, reduced Return on Equity and incentive specified in these Regulations.

5.3 Deviation from ceiling tariff determined by the Commission, shall come into effect from the date agreed to by Generating Company and Beneficiaries.

5.4 Generating Company and Beneficiaries of a Generating Station shall be required to intimate the Commission for charging lower tariff in accordance with Regulations 5.1 to 5.3 of these Regulations. The details of the accounts and the tariff actually charged under Regulations 5.1 to 5.3 of these Regulations shall be submitted at the time of true up.

5.5 Revenue loss on account of charging lower than approved tariff shall be borne entirely for all times by Generating Company and the impact of such revenue loss shall not be passed on to Beneficiaries, in any form."

3 GENERAL PRINCIPLES

3.1 Multi Year Tariff Framework

3.1.1 The Commission proposes to continue with a Control Period of five years from April 01, 2024 to March 31, 2029.

3.1.2 As per the GERC MYT Regulations, 2016, the MYT Framework was based on the detailed MYT Application comprising the forecast of Aggregate Revenue Requirement for the entire Control Period, a Mid-term Review of the Aggregate Revenue Requirement and annual truing up and tariff determination for all the utilities including the Generating Companies, Transmission Licensees, SLDC and the Distribution Licensees.

3.1.3 The Mid-Term review is a crucial process for the Commission in evaluating the performance of these utilities, making regulatory decisions, identifying issues and make necessary adjustments, align policies with market dynamics, and fosters stakeholder engagement. The Mid-Term review also helps in identifying areas for efficiency improvements and refine strategic planning to ensures continuity and consistency in the Commission's Regulatory approach. Therefore, the Commission believes that there is need for provisions which has detailed methodology for calculating the Aggregate Revenue Requirement for the remaining years of the Control Period.

Suggestion/Comment from Stakeholders:

1) Torrent Power Limited (TPL) has submitted that considering variability of parameters affecting tariff TPL has suggested to continue with existing methodology of Annual tariff determination for all the utilities instead of Mid-Term Review for the Generating Companies, and Transmission Licensees or SLDC. Further, TPL feels that Annual Tariff determination for all utilities is important to address Gap/ Surplus at the earliest and avoid burden of carrying cost.

2) Gujarat Urja Vikas Nigam Limited (GUVNL) has submitted that in case of a Distribution Licensee, the power purchase cost is the major cost contributor, which depends upon the consumer mix, consumption pattern, cost of fuel, etc. These factors further depend upon factors which are dynamic in nature and will significantly vary on annual basis and any delay in pass through of gain/loss in the tariff will impact liquidity of Distribution Utilities apart from implications towards carrying cost. Further, truing-up exercise other than that on an yearly basis may lead to accumulation of revenue gain/loss and consequent tariff shock to consumers due to steep tariff increase. Accordingly, GUVNL requested to provide annual truing up exercise for Distribution Utilities.

3) Prayas Energy Group (PEG) has submitted that regular true up process is crucial to

the effective functioning of the utility but it is understood that an annual undertaking is a time intensive exercise for utilities and the Commission. In order to address this; while ensuring regulatory certainty for costs and tariffs, tracking and holding the utility accountable for its performance in the medium term, and to help with medium term planning; truing up can be carried out twice in a five year control period. The true up for the first two years (and provisional true up for the 3rd year) can be carried out during the mid term review process (carried out in the third year of the control period). The mid term review could also be used to revise the parameters for the remaining control period, if required. Final truing up for the last three years of the control period can be carried out at the end of the control period. PEG has further suggested that this treatment should be applicable to all utilities in order to ensure course correction if needed and reduce risks, while providing certainty to stakeholders.

4) Jivabhai Patel has submitted the Regulations for the States of Assam, Madhya Pradesh, Punjab and Uttar Pradesh for reference to the Commission and has suggested that the same be considered while framing the GERC MYT Regulations 2023.

3.1.4 Considering the stakeholders' comments as well as with a view to gradually shift from annual tariff determination process to a Multi-Year Tariff determination regime, the Commission, in the draft GERC MYT Regulations, 2023 has proposed to shift from annual truing-up exercise to Mid-Term Review during the third year in case of Generating Company, Transmission Licensee and SLDC, while continuing with annual truing-up exercise in case of Distribution Licensee. Accordingly, the Commission has proposed the following MYT framework for the fourth control period:

*"**16. Multi-Year Tariff Framework***

16.1. The Commission shall determine the tariff, Fees and Charges for matters covered under clauses (a) to (e) of Regulation 3.1 of these Regulations, under a Multi-Year Tariff framework with effect from April 01, 2024:

Provided that the Commission may, either on suo-motu basis or upon application made to it by an Applicant, exempt the determination of tariff or Fees and Charges of a Generating Company or Transmission Licensee or SLDC or Distribution Licensee under the Multi-Year Tariff framework for such period as may be contained in the Order granting such an exemption.

16.2 Filing under Multi-Year Tariff Framework by Generating Companies, Transmission Licensees, SLDC and Distribution Licensees, shall be done as per the timelines and in compliance with the principles for determination of Aggregate Revenue Requirement as specified in these Regulations, in such form as may be *prescribed by the Commission from time to time.*

16.3 Multi-Year Tariff Framework shall be based on the following elements, for determination of Aggregate Revenue Requirement and estimated revenue from Tariff and Fees and Charges for the Applicant:

16.3.1 Multi-Year Tariff Petition comprising forecast of Aggregate Revenue Requirement for the entire Control Period and expected revenue from existing tariff or Fees and Charges, expected revenue gap or surplus, for each year of the Control Period, shall be submitted by the Applicant:

Provided that Generating Company, Transmission Licensee or SLDC shall also submit proposed tariff or Fees and Charges for each year of the Control Period:

Provided further that Distribution Licensees shall propose the category-wise tariff only for the first year of the Control Period:

Provided further that performance parameters, whose trajectories have been specified in these Regulations, shall form the basis for projection of Aggregate Revenue Requirement for the Control Period:

Provided also that Multi-Year Tariff Petition shall also include truing up for FY 2022-23 or for any financial year prior to FY 2022-23 for which truing-up is yet to be completed, to be carried out under Gujarat Electricity Regulatory Commission (Multi-Year Tariff) Regulations, 2016.

16.3.2 The Commission shall determine the Aggregate Revenue Requirement and tariff or Fees and Charges for Generating Companies, Transmission Licensees and SLDC for each year of the Control Period, at the beginning of the Control Period.

Provided that the Commission shall also approve the sharing proportion amongst the Transmission System Users for the SLDC Fees and Charges for the Control Period.

16.3.3 The Commission shall determine Aggregate Revenue Requirement for Distribution Wires Business and Retail Supply Business for each year of the Control Period and tariff for the first year of the Control Period, at the beginning of the Control Period.

16.3.4 A Mid-Term Review petition for truing-up of the Aggregate Revenue Requirement for the first two years of the Control Period based on the audited books of accounts, vis-à-vis the approved forecast for the respective years shall be submitted by Generating Companies or Transmission Licensees or

SLDC along with its Petition for Aggregate Revenue Requirement for last two years of the Control Period by November 30th of the third year of the Control Period:

Provided that the Mid-Term Review petitions shall include information in such form as may be stipulated by the Commission, together with the Accounting Statements, extracts of books of account and such other details, including Cost Accounting Reports or extracts thereof, as it may require to assess the reasons for and extent of any difference in operational and financial performance from the approved forecast of Aggregate Revenue Requirement.

Provided that the Mid-term Review petition shall also include truing up for FY 2023-24 or for any financial year prior to FY 2023-24 for which truing-up is yet to be completed, for Generating Companies, Transmission Licensees or SLDC, along with the audited annual accounts of the respective financial year, to be carried out under Gujarat Electricity Regulatory Commission (Multi-Year Tariff) Regulations, 2016:

Provided further that true-up petition for the third, fourth and fifth years of the Control Period for Generating Companies, Transmission Licensees and SLDC, under these Regulations shall be submitted during the subsequent Control Period.

16.3.5 The Commission shall determine the revised Aggregate Revenue Requirement and tariff or Fees and Charges for Generating Companies, Transmission Licensees and SLDC for the fourth and fifth year of the Control Period based on the Mid-term Review. Further, the Commission shall also undertake truing-up for the first and second years of the Control Period, and categorization of variation in performance as those caused by factors within the control of the petitioner (controllable factors) and by factors beyond its control (uncontrollable factors), along with the Mid-Term Review"

3.1.5 Further, for the Distribution Licensees, the Commission has proposed the following MYT framework for the fourth control period:

"16.3.6 Petition for annual truing-up of operational and financial performance for the previous year of the Control Period based on Audited Accounts, and revised forecast of Aggregate Revenue Requirement, expected revenue from existing tariff, expected revenue gap or surplus, and proposed category-wise tariff for the ensuing year of the Control Period, shall be submitted by the Distribution Licensees for their respective Distribution Wires Business and Retail Supply Business by November 30th of each year of the Control Period:

Provided that Distribution Licensee shall submit the information in such formats as may be prescribed by the Commission, together with the Audited Accounts, extracts of books of account, cost to serve study for the truing-up year *and such other details as the Commission may require to assess the reasons for and extent of any variation in financial performance form the approved forecast of Aggregate Revenue Requirement and expected revenue from tariff and charges:*

Provided further that petition for truing-up for FY 2023-24 or for any financial year prior to FY 2023-24 for which truing-up is yet to be completed, for Distribution Licensees, shall also be submitted along with the audited annual accounts of the respective financial year, in accordance with the provisions of Gujarat Electricity Regulatory Commission (Multi-Year Tariff) Regulations, 2016:

Provided further that true-up Petition for the fourth and fifth years of the Control Period by Distribution Licensees for their respective Wire and Retail Supply Businesses, under these Regulations shall be submitted during the subsequent Control Period."

3.1.6 Further, as per the GERC MYT Regulations 2016, the Carrying cost was to be allowed on the amount of Revenue Gap or Revenue Surplus is calculated based on the State Bank of India Base rate for the relevant year and the period considered is from the date on which such gap/surplus has become due, i.e., from the end of the year for which true-up has been done, till the end of the year in which it is addressed.

3.1.7 Regulation 21.6 in the existing Regulations specifies as follows:

*"**21 Truing Up***

…

21.6 Upon completion of the Truing Up, the Commission shall pass an order recording:

….

(c) Carrying cost to be allowed on the amount of Revenue Gap or Revenue Surplus for the period from the date on which such gap/surplus has become due, i.e., from the end of the year for which true-up has been done, till the end of the year in which it is addressed, calculated on simple interest basis at the weighted average State Bank Base Rate for the relevant year, i.e. the year for which Revenue Gap or Revenue Surplus is determined:

Provided that carrying cost on the amount of Revenue Gap shall be allowed up to the above limit, subject to prudence check and submission of documentary *evidence for having incurred the carrying cost in the years prior to the year in which the revenue gap is addressed;*

…"

Suggestion/Comment from Stakeholders:

1) **GUVNL** has submitted that it may be difficult for utilities to provide documentary evidence for incurring carrying cost of revenue gap as the revenue gap may be met through internal accruals for which specific documentary evidence may not be available. Once the Commission approved revenue gap for previous year and allow same to be recovered in ensuing year, carrying cost need to be allowed irrespective of if it is actually incurred or it is met through internal accruals.

2) **Adani Power Limited** has submitted that Carrying / holding cost should be allowed on the basis of compound interest as settled by Hon'ble Supreme Court in its Uttar Haryana Judgment in Civil Appeal 7129 of 2021 dated 24.08.2022.

3) **TPL** has submitted while discussing the computation of Carrying cost, the Discussion Paper has inadvertently missed out the recent APTEL/ Supreme Court Judgements, which is also reflected in the Commission's recently issued tariff order. Further, while calculating the Carrying cost, following shall be considered:

   i. APTEL has observed that interest rate applicable for short-term working capital requirement should be considered for Carrying cost.

   ii. CERC Regulations provides for carrying cost @ 1-year MCLR + 350 basis points.

3.1.8 The Commission has observed that the submission on allowing carrying / holding cost on the basis of compound interest i.e. addition of trued up gap of the previous year (i.e., year of which trued up is carried on) with carrying cost to be added in the ARR of current year and then again carrying cost allowed on such trued up gap, instead of simple interest as per existing GERC MYT Regulations, 2016, the Commission is of the view that the facts and circumstances of the said judgment in Civil Appeal 7129 of 2021 dated 24.08.2022 by the Hon'ble Supreme Court Judgment were completely different. The said Judgment is primarily based on the 'restitutionary principles', (i.e. restoring the benefit to a party that is adversely affected by a Change in Law event and restore it to its original economic position as if such a Change in Law event had not taken place) for computing the impact of change in law which the parties agreed (procurer and generator) in the PPA entered upon between them.

3.1.9 It is observed that the Commission has not proposed any fundamental change in the provisions of the existing GERC MYT Regulations, 2016, applicable since 2016-17, are still in effect and have not been held ultra-vires by any of the superior court(s). It is also worth mentioning here that even in case of consumer security deposits and delayed payment surcharge on retail consumers, the computation is done on simple interest basis and not on compounded interest basis. It is further observed that the neither the EA, 2003 nor the Tariff Policy or any other Law, specifically mandates the recovery of carrying cost with compounded interest. Accordingly, the Commission is of the proposed methodology of continuing the provision of existing GERC MYT Regulations, 2016 w.r.t computation of carrying cost on 'simple interest basis' is apt to meet the multi-facet objectives of ensuring timely payment, enforcing financial discipline and avoiding over burdening the consumers' retail tariff and also in accordance with law. It is a settled principle of law that compound interest cannot be granted unless the statute specifically provides or parties specifically agrees for it in the contract or there has been any breach or wrong doing on the part of the person requiring to pay the amount. In case of determination of tariff and its truing up there is no case of any breach or wrong doing on the part of any person. The truing up may take time for number of reasons, Act of court/tribunal cannot be construed as a default of wrong doing to allow interest on compounding basis as restitution.

3.1.10 Taking into consideration the comments of the stakeholder as well as balancing the interest of the consumers, the Commission proposes for the following provision w.r.t carrying cost:

"16.7 Upon completion of the Mid-Term Review or truing up, the Commission shall pass an order recording:

….

(c) carrying/holding cost to be allowed on the amount of revenue gap or revenue surplus for the period from the date on which such gap/surplus has become due, i.e., the interest should be calculated for the period from the middle of the financial year in which the revenue gap/surplus had occurred upto the middle of the financial year in which the recovery has been proposed, calculated on simple interest basis at the weighted average rate of one year SBI MCLR or any replacement thereof by SBI from time to time being in effect applicable for 1 year period, as applicable prevailing during the relevant year, i.e., the year for which revenue gap or revenue surplus is determined:

Provided that carrying cost on the amount of revenue gap shall be allowed up to the above limit, subject to prudence check and submission of documentary evidence for having incurred the carrying cost in the years prior to the year in which the revenue gap is addressed:

Provided further that carrying cost or holding cost shall be allowed on the net entitlement after sharing of efficiency gains and losses as approved after true-

up.”

3.1.11 Further, in view of the changes in the accounting statements, the Ministry of Corporate Affairs (MCA) had notified IND AS which has been implemented from FY 2017-18 onwards. Prior to this, the companies used to prepare and report financial statement based on GAAP (Generally Accepted Accounting Principles). However, Ministry of Corporate Affairs (MCA) issued a note dated January 2, 2015, outlining the various phases, in which Indian Accounting Standards (IND AS) converged with IFRS has to be implemented in India, for Companies other than Banking Companies, Insurance Companies and NBFCs. Accordingly, IND AS was made mandatory from FY 2016-17 for all companies with Net Worth of not less than Rs. 500 crores and from FY 2017-18, for all listed companies and unlisted company with Net worth greater than Rs. 250 crores. Since the financial statement of applicants has been reported under IND AS, the financial reporting format differs than the earlier Financial Year accounting statement which were prepared under GAAP. One key fundamental change is the significant increase in focus on fair value accounting where IND AS requires application of fair value principles, which would result in significant differences from financial information being presented under GAAP. Also, under IND AS, the fair value of assets are revalued at fair value periodically, so that the carrying amount of an asset does not differ materially from its fair value at the balance sheet date. Also, Current Liabilities and Debt under GAAP has been bifurcated into Short Term and Long Term Liabilities under IND AS. Considering the different principles of preparation and reporting of financial statement compared to the preparation of ARR which follows historical accounting approach, there is a need for reconciliation of ARR formats with the financial statement prepared under IND AS. Therefore, the Commission proposes for inclusion of the following proviso under ‘Multi-Year Tariff Framework’ Regulations:

“Provided further that Generating Companies, Transmission Licensees, SLDC and Distribution Licensees shall provide reconciliation statement, duly certified by the Statutory Auditors, showing the accounting statement under Indian Accounting standard (IND AS) and Generally Accounting Accepted Principles (GAAP) as per financial statement and regulatory formats.”

3.1.12 Further, there are no regulations specific to the Incumbent Distribution Licensees in GERC MYT Regulations 2016. Incumbent distribution licensees play a crucial role in the electricity sector as they are the established entities responsible for distributing electricity within specific geographic regions. Their importance lies in maintaining the reliable and efficient distribution of electricity to consumers and ensuring the smooth functioning of the power supply chain. The Incumbent Distribution Licensees also contribute to the overall development and growth of the electricity sector by investing in infrastructure, improving service quality, and promoting technological advancements. Therefore, the Commission proposes for inclusion of the following proviso under 'Multi-Year Tariff Framework' Regulations.

"*16.9 Incumbent Distribution Licensees shall have the option of filing separate petitions under these Regulations for an area in respect of which the Commission has issued multiple Distribution Licenses:*

Provided that each such separate petition shall contain all necessary details of expenses, revenue, assets, liabilities, capitalisation, and category-wise tariff to enable the Commission to determine the Aggregate Revenue Requirement and tariff for each separate area for which it has been filed:

Provided further that such expenses, revenue, assets, liabilities, and capitalisation considered for each such area shall be excluded while submitting the petition for the remaining area of supply:

Provided also that Distribution Licensee shall submit the reconciliation statement for expenses, revenue, assets, liabilities, and capitalisation between the entity as a whole and each such separate area of supply for which Distribution Licensee has filed a separate petition."

3.2 Multi- Year Tariff Application

3.2.1 As per the GERC MYT Regulations 2016, the Distribution Licensee shall project the power purchase requirement based on the Merit Order Despatch (MOD) principles of all Generating Stations considered for power purchase, the Quantum of Renewable Purchase Obligation (RPO) under Regulation 4 of Gujarat Electricity Regulatory Commission (Procurement of Energy from Renewable Sources) (First Amendment) Regulations, 2014 and the target set, if any, for Energy Efficiency (EE) and Demand Side Management (DSM) schemes.

3.2.2 However, in line with the recent requirements of Resource Adequacy in line with the provisions mentioned in the Electricity (Amendment) Rules, 2022, and the Guidelines for Resource Adequacy Planning Framework issued by the Ministry of Power, the Commission proposes for inclusion of the following proviso under 'Multi-Year Tariff Application' Regulations:

"17.4 Distribution Licensee shall project the power purchase requirement, taking into consideration, the Resource Adequacy Guidelines issued by Ministry of Power, Government of India, its Long-term Discom Resource Adequacy Plan (LT-DRAP), as vetted by the Central Electricity Authority, Merit Order Despatch principles of all Generating Stations considered for power purchase, quantum of

Renewable Purchase Obligation (RPO) under Gujarat Electricity Regulatory Commission (Procurement of Energy from Renewable Sources) Regulations, 2014, as amended from time to time, and the target set, if any, for Energy Efficiency (EE) and Demand Side Management (DSM) schemes:

Provided that Merit Order Despatch principles shall not apply to purchase of power from Renewable Energy sources up to the RPO specified by the Commission:

Provided further that at the time of filing of the MYT Petition, in case the Long-term Discom Resource Adequacy Plan (LT-DRAP), as vetted by the Central Electricity Authority is not finalized, the finalized plan shall be filed along with the ARR and determination of tariff petition for the second year of the Control Period."

3.3 Controllable and uncontrollable factors

3.3.1 The GERC MYT Regulations 2016 defines the controllable and uncontrollable factors and the mechanism for sharing of losses/gains on account of the same that are to be shared between the Utility and the consumer. Therefore, it is essential to clearly specify the controllable factors and uncontrollable factors based on which the sharing of losses/gains to be determined for the Utility.

Suggestion/Comment from Stakeholders:

1) Gujarat State Electricity Corporation Limited (GSECL) has submitted that the extra financial burden on account of wage revision/ hike in the dearness allowance (DA) may be included as Uncontrollable parameter because this factor is beyond the control of GSECL. Further, the delay in execution of new power generation project, the time and cost overruns on account of obtaining connectivity to the transmission system and the delay due to matters of acquisition of land or getting Right of Way due to factors not attributable to generation company should also be allowed as uncontrollable parameter.

2) GUVNL has submitted that in case a second distribution license granted in the area of existing distribution licensee, the incumbent distribution licensee do not have level-playing field as new entered distribution licensee is operating in a compact and more controlled manner. Further, overall supply area, consumer mlx and network condition of incumbent distribution licensee is not comparable with newly entered distribution licensee. Moreover, incumbent distribution licensee has a universal supply obligation and do not have the option to choose consumers. Thus, the reasons for migration of consumers from existing distribution licensee is not attributable to licensee. Under the circumstances, it is not appropriate to consider such variation as controllable factor

Moreover it is apprehended that new entrant licensee will supply power to cross subsidizing consumers only. Therefore, GUVNL has requested to consider that the variation in the number or mix of consumers or quantities of electricity on account of migration of consumer from existing licensee to newly entered licensee as uncontrollable.

Commission's Views:

3.3.2 The Commission has considered the Stakeholder comment. In addition to the existing parameters, the Commission has proposed addition of 'delay in statutory clearances for land acquisition' to the 'Uncontrollable Factors" because these delays cannot be reduced and it's beyond the control of the Petitioner. The following proviso under 'Controllable and uncontrollable factors' Regulations specify the same:

"19.1 For the purpose of these Regulations, the term "uncontrollable factors" shall comprise of the following factors, which were beyond the control of the Applicant, and could not be mitigated by the Applicant:

(a) Force Majeure events;

(b) Change in law; judicial pronouncements, and orders of the Central Government, the State Government or the Commission;

(c) Economy wide influences such as unforeseen changes in inflation rates, taxes and statutory levies;

(d) Delay in statutory clearances for land acquisition;

(e) Variation in the price of fuel and/ or price of power purchase;

(f) Variation in the number or mix of consumer or quantities of electricity supplied to consumers;

Provided that where there is more than one Distribution Licensee within the area of supply of the Applicant, any variation in the number or mix of consumers or in the quantities of electricity supplied to consumers within the area served by two or more such Distribution Licensees, on account of migration from one Distribution Licensee to another, shall be attributable to controllable factors;

(g) Income from realisation of bad debts written off:

Provided that where the Applicant believes, for any variable not specified above, that there is a material variation or expected variation in performance for any financial year on account of uncontrollable factors, such Applicant may apply to *the Commission for inclusion of such variable at the Commission's discretion, under these Regulations for such financial year."*

3.4 Mechanism for sharing of gains or losses on account of controllable factors

3.4.1 As per the GERC MYT Regulations 2016, one-third of the amount of aggregate gain on account of controllable factors shall be passed on to the consumers as a rebate in tariffs. One-third of the amount of aggregate loss on account of controllable factors may be passed on as an additional charge in tariffs for all the utilities including Generating Company or Transmission Licensee or SLDC or Distribution Licensee.

Suggestion/Comment from Stakeholders:

1) TPL - The Commission proposed that 2/3rd controllable Gain to be retained and 1/3rd controllable Gain to be passed on to the consumers and no controllable losses should be pass through. TPL's view is that there should not be any discrimination between sharing of gains/ losses and if utility bears a certain percentage of losses for not achieving the performance targets, similar percentage of gains should also be allowed to utility better performance. TPL suggests that sharing of Gains and Losses should be on equitable basis.

2) Adani Power Limited (APL) - Gains or losses on account of controllable parameters are due to operational efficiencies and prudent utility practices followed by generating company or licensees and therefore, the existing sharing ratio to be retained as it is fair to both consumers and licensees.

3) GSECL - It is opined that the present methodology of sharing of gain/loss on account of controllable parameters seems to be appropriate and may not be modified.

4) MUL - Gains or losses on account on controllable parameters are due to operational efficiencies and prudent utility practices followed by utilities and therefore, the existing sharing ratio should be retained as it is fair to both consumers as well as utilities.

5) PEG – PEG has submitted an effective gain/loss sharing mechanism should provide effective incentives to the utility to reduce losses on account of controllable parameters, while also reducing consumer tariffs and protecting consumer interests. Toward this, PEG has suggested that the Commission should consider increasing the proportion of gains shared with the consumer, and reducing the share of losses passed on or consider adopting CERC's gain/loss sharing mechanism, wherein 50% of the gains on account of controllable parameters are passed on to the consumer, but no losses are shared.

6) GUVNL - With regard to Sharing of Gain/ Losses on Controllable Parameters, GUVNL has submitted that any gain/ surplus available to distribution licensee is invested in the

distribution business itself to improve the performance of the utility and customer services. GUVNL also submits that the proposition for pass through of gain without allowing pass through of controllable loss or pass through of gain at higher level as compared to pass through of loss, would ultimately affect the ability of the distribution licensee to absorb the revenue loss on other account resulting into overall loss which will ultimately affect the ability of the distribution licensee in performance improvement and betterment of customer service. Therefore, GUVNL requests to allow pass through of gain and loss at same level.

Commission's Views:

3.4.2 The Commission has considered the comments of the stakeholders. As per the National Tariff Policy, 2016 suitable performance norms of operations together with incentives and disincentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Therefore, the Tariff Policy, 2016 clearly specifies that 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. Accordingly, during the transition period, gains of efficient operations with reference to normative parameters was appropriately shared between consumers and licensees with higher share with the Utilities.

3.4.3 However, the current phase of implementation of MYT Regulations, is far ahead of the transition phase and has already achieved the maturity stage and therefore, it is necessary that though the sharing of incentives may be considered on asymmetric basis but with the objective to pass on higher benefits to the consumers.

3.4.4 The profit-sharing mechanism is intended to share the benefits of better performance of the Utility with the consumers. Also, the Tariff Policy, 2016 clearly states that pass through of losses to be allowed only to the extent of uncontrollable factor and therefore, any loss related to controllable factor needs to be retained by the Utility. However, to balance out the interest of the Utilities and the Consumers with the intention to achieve the objective of Tariff Policy, 2016, the Commission has proposed to amend the Regulations on 'Mechanism for sharing of gains or losses on account of controllable factors' to allow higher gains on account of controllable factors to be passed on to consumers as rebate in tariff and in case of losses, higher share of losses to be absorbed by the Utilities.

3.4.5 It is submitted that though the mechanism of sharing of gains and losses may be asymmetric, the Commission has already specified controllable factors and the operating norms for Utilities. Therefore, it is proposed that two-third of the gains on account of controllable factors shall be shared with the consumers against the existing approach of one third of the gain to be passed on to the consumers.

3.4.6 Further, it may be noted that FOR Report on MYT Framework recommends that no sharing of losses shall be passed on to the consumer. Also, CERC Tariff Regulations, 2019 has specified that no sharing of losses on account of controllable factors with the consumers is to be undertaken due to the fact that any sharing of losses would imply that the Utilities have not put in adequate efforts to sustain even at the normative performance parameters specified by the Commission contrary to the expected improvement. Therefore, passing on such losses on account would not be appropriate and would discourage improvement in efficiency. However, the Commission intends to reach there gradually and therefore, is considering only one third of the losses to be passed on to the consumers.

3.4.7 Accordingly, the proposed Regulation is as reproduced below:

"21.1 The approved aggregate gains to Generating Company or Transmission Licensee or SLDC or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) Two-third of the amount of such gains shall be passed on as a rebate in tariff over such period as may be stipulated in the order of the Commission under Regulation 16.7 these Regulations; and

(b) Balance amount of such gains shall be retained by Generating Company or Transmission Licensee or SLDC or Distribution Licensee.

21.2 Approved aggregate losses to Generating Company or Transmission Licensee or SLDC or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such losses may be passed on as an additional charge in tariffs over such period as may be stipulated in the order of the Commission under Regulation 16.7 of these Regulations; and

(b) Balance amount of such losses shall be absorbed by Generating Company or Transmission Licensee or SLDC or Distribution Licensee.

21.3 Approved gains or losses to Generating Company or Transmission Licensee or SLDC or Distribution Licensee on account of variation in interest rate on long term loan shall be dealt with in the manner as specified in Regulation 33 of these Regulations.;"

3.5 Filing Procedure

3.5.1 Technical validation in GERC tariff petitions is crucial as it ensures that the proposed tariffs are based on accurate technical data and calculations. This validation helps maintain the credibility, transparency, and fairness of the tariff-setting process, preventing incorrect or misleading information from influencing the decision-making. It also aids in creating a level playing field for all stakeholders and ensures that consumers are charged appropriately for the services provided. The GERC MYT Regulations 2016, has not specified any Technical Validation session prior to the admission of the Petition. Therefore, the Commission proposes for inclusion of the Technical Validation session prior to the admission of the Petition along with submission of text-searchable format or in downloadable spreadsheet format and showing detailed computations, all regulatory filings, information, particulars and documents in the manner stipulated by the Commission. The following provisos have been proposed to be added under the Regulations for 'Filing Procedure':

> *"25.1 …..*
> *Provided also that the Commission, or the Secretary or any Officer designated for the purpose by the Commission, may conduct a Technical Validation session prior to the admission of the petition.*
>
> *25.4 ….:*
> *Provided that the Petitioner shall make available a hard copy of the complete Petition to any person, at such locations and at such rates as may be stipulated by the Commission:*
> *Provided further that the Petitioner shall also provide on its internet website, in text-searchable format or in downloadable spreadsheet format and showing detailed computations, the petition filed before the Commission along with all regulatory filings, information, particulars and documents in the manner stipulated by the Commission:*
> *Provided also that the web link to the complete petition, including its formats and any additional information, shall be easily accessible, archived for downloading and be prominently displayed on the Petitioner's internet website:*
> *Provided also that the Petitioner may be exempted by the Commission from providing any such information, particulars or documents as are confidential in nature."*

3.6 Subsidy Mechanism

3.6.1 The Section 65 of the Electricity Act, 2003 in India pertains to the "Duty to furnish information, return, etc." As per Section 65, the licensees, generating companies, and any other person connected with the business of generation, transmission, distribution, or trading of electricity are required to provide information, returns, and statistics to the appropriate State or Central Electricity Regulatory Commission, as needed. This provision helps in maintaining transparency, monitoring the electricity sector, and making informed regulatory decisions. Further, the recently notified Electricity (Second Amendment) Rules, 2023 has also included provisions pertaining to 'Subsidy accounting and payment', casting certain responsibilities on the State Commission. Accordingly, the existing Subsidy Mechanism Regulations needs to be amended to address the issue of data transparency for availing the subsidies. Therefore, the Commission proposes the inclusion of the following proviso under 'Subsidy Mechanism' Regulations.

"28.2 Accounting of the subsidy payable under section 65 of the Act, shall be done by the Distribution Licensee, in accordance with the Standard Operating Procedures issued by the Central Government, in this regard.

28.3 Distribution Licensee shall submit to the Commission a quarterly report consisting of details w.r.t demands of subsidy raised by Distribution Licensee to the State Government during the relevant quarter based on the accounts of the energy consumed by the subsidised category and consumer category wise per unit subsidy declared by the State Government, the actual payment of subsidy in accordance with section 65 of the Act and the gap in subsidy due and paid as well as other relevant details, as may be specified by the Commission and / or Ministry of Power vide its Rules framed under the provisions of the Act.

28.4 In case subsidy has not been paid in advance, the Commission shall issue order for implementation of the tariff without subsidy, in accordance with provisions of the section 65 of the Act;"

4 FINANCIAL PRINCIPLES

4.1 Capital Cost

4.1.1 The capital cost of the project is a base for tariff determination in the current cost-plus tariff regime. The capital cost directly influences the ARR components such as Interest on Loan, Return on Equity, Depreciation and consequent Interest on Working Capital and therefore largely affects the end user tariffs.

4.1.2 With respect to the power granted under Sections 61, 86 and 181 of Electricity Act, 2003 and the guidelines under Section 5.7 and sub-section 5.8.4 of National Electricity Policy, 2005, the Commission is dedicated to safeguarding consumer interests and drive investments in the sector. Further, there have been various important judgements form APTEL, higher courts, etc, recommendations from Forum of Regulators and Central Electricity Authority (CEA) on MYT Framework. Additionally, considering the recent developments in the power sector in the country, the Commission has reassessed the components of capital cost and accordingly, added a few provisions in the draft GERC MYT Regulations, 2023.

4.1.3 Taking cognizance of the recent developments in the power sector the Commission has decided to reassess the capital cost components such as Hard Cost, Interest During Construction (IDC), Incidental Expenditure during Construction (IEDC), Initial Spares, ACE, foreign exchange rate variation (FERV), etc. The determination of Capital Cost as per GERC MYT Regulations, 2016 was based on actual cost incurred on the project and project developer was to approach for final tariff determination after declaration of the Commercial Operation Date. Since higher courts have brought forth better clarity in terms of aspects like Foreign Exchange Rate Variation through its 2019 ruling in Civil Appeal no. 684 of 2007. Hence, such recent developments in the power sector and the effect of capital cost on tariff determination warrants a reassessment of the Capital Cost component.

4.1.4 Currently, the GERC MYT Regulations, 2016 provides approval for capital expenditure through due prudence check. But there is a need for regulating the Capital Investment Schemes in an unambiguous and transparent manner which is critical for providing regulatory certainty, for promoting efficient and optimal utilization of resources.

4.1.5 The Commission needs to assess to its satisfaction that the Petitioner has examined all viable alternatives in environmental, economic and technical aspects to the proposal for investing in or acquiring new Generation/Transmission/Distribution System assets and has explored all possible avenues in sourcing the funds thus ensuring that they have opted for the most economical and efficient approach.

Issues Discussed in Concept Paper

4.1.6 Since the Capital Investment Scheme have a significant impact on the overall tariff, the Consultation paper has discussed the following issues as well. With a view to further regularize and streamline the filing and approval process of Capital Investment Schemes, a need is felt for developing a comprehensive Capital Investment Plan approval process, covering various aspects including threshold limit for prior approval, process of submission for approval, details required for prudence check, etc.

4.1.7 It is observed that most of the SERCs have not yet provided separate guidelines and/or Regulations for Capital Investment Scheme approval framework. While few have defined broad guidelines, Maharashtra Electricity Regulatory Commission has notified MERC (Approval of Capital Investment Schemes) Regulations, 2022, which has comprehensively detailed out the process of capex approval for power utilities covered under regulated tariff mechanism. It is proposed to develop a comprehensive Capital Investment Scheme approval framework for the utilities in State of Gujarat.

Suggestion/Comment from Stakeholders:

1) MPSEZ Utilities Limited (MUL) has requested the Committee to keep the existing methodology, since most of the SERCs are following the same and further introduction of Capital Investment Scheme Approval framework will be duplication of work for both Distribution Licensee and Commission Staff.

2) Adani Power Limited has provided the view that delinking of capital investment schemes from the MYT process will enable developers/licensees to seek timely approvals which will aid in optimizing the project timelines.

3) Federation of Kutch Industries Associations (FOKIA) has commented that GETCO has been submitting year wise capital expenditure to be incurred in voltage wise schemes for lines and substations and the Commission approves the same after due deliberations. However, as has been repeatedly observed in the past, while execution, approved amounts are not utilized in voltage system-wise. This needs to be monitored while approving the true-up data and cost overruns due to delays and this should not be approved and passed on to the consumers. Also, the expenditures for the 66 kV system are generally very high w.r.t. approved every year, as has been observed in the past. This needs to be checked to ensure that there are valid genuine reasons beyond control and requirements of such additional expenditure are justifiable.

4) Paras Energy Group has submitted that a framework to streamline the approval process of such schemes will aid in ensuring added clarity and scrutiny of such capital expenditure. Additionally, given the useful life of TPPs, could potentially cause

resource lock-ins leading to fixed cost liability for the procurers and their consumers which may not be warranted. Thus, prudence checks towards capital investment schemes should also include justification of the necessity of the project itself to prevent cost and resource lock-ins.

5) GSECL has pointed out that it carries out the Capital Investment plans after specific approval by GoG and allotment of specific budget as an equity contribution with detailed analysis and deliberations. Since the process to obtain specific approval of the Hon'ble Commission is already in existence, no such additional framework of obtaining prior approval is required in the new MYT Framework.

6) GUVNL has prayed to the commission that

   a) keeping in mind the Universal Service Obligation for Distribution licensees the investment is mainly towards large numbers of schemes involving small amounts, which will make entire process cumbersome and lead to delay in providing consumer services.

   b) Other states with similar prior approval of investment schemes have well established mechanisms and framework which may be lacking in case of State of Gujarat. In view of the above the Hon'ble Commission is requested to continue with existing practice of CAPEX approval.

   c) In case Capital Investment Approval Framework is introduced then investment towards Government Schemes and investments for release of connection /load extension for discharging Universal Service Obligation may be exempted from same.

7) TPL has commented that proposed mechanism amounts to micromanagement since Concept like threshold limit for in-principle approval, Geo-tagging, Utilisation Index etc. are practically difficult to implement considering widespread network and USO requirements further pointing to:

   a) Concept of restriction on Capex in case of Parallel licensee is already under legal disputes as same is contradictory to the Act. Act provides distribution licensee to lay its own network.

   b) We understand that issue of Utilization Index is already dealt with by APTEL in the matter of GIFT City. Further, the same will penalize the Utility fortaking futuristic approach to cater to the demand of its consumers as it is not possible to create the network only to meet the existing demand.

   c) These concepts have also not yielded any tangible benefits.

Hence the existing mechanism of approval should be continued further there cannot be any discrimination of CAPEX Approval for State Discoms or Private Discoms.

Commission's View

4.1.8 The Commission has noted the submissions made by the stakeholders in this regard.

4.1.9 For the existing projects, the capital cost admitted by the Commission before April 01, 2024 and ACE projected to be incurred for the respective year of the Control Period 2024-29 will form the basis for determination of tariff as may be admitted by the Commission.

4.1.10 Under Regulation 34 of the GERC MYT Regulations, 2016, the determination of capital cost was based on actual cost incurred on the project and the project developer was to approach for final tariff determination after declaration of Date of Commercial Operation (COD). The capital cost changes were accounted for through capitalization and foreign exchange rate variation (FERV), while the tariff was determined later. The existing provisions dealing with FERV state that any gain or loss on account of FERV on the loan during construction period up to COD was to be included in capital cost. However, the Hon'ble Supreme Court, vide its ruling in Civil Appeal No. 684 of 2007 and 13452 of 2015 dated May 9, 2019, has brought forth greater elucidation regarding the handling of FERV. The Court has explicitly indicated that the entirety of FERV should only be allocated in relation to debt liabilities. Thus, to add more clarity on FERV, the Commission has modified the Regulation 34.1 (a) of GERC MYT, 2016 and added sub-clauses (d) in Regulation 29.2 of Draft GERC MYT, 2023.

4.1.11 The Cost for Rehabilitation and Resettlement plan for existing or new hydro Generating Station shall be included in the Capital Cost in conformity with Chapter 4, 5 and 6 of the National R&R Policy, 2007 along with other relevant sections of the same and R&R Package as approved.

4.1.12 For the exclusions from capital cost of the existing and new projects, the Commission has decided to include De-capitalised assets after COD on account of replacement/removal due to obsolescence or shifting from one project to another, in case of hydro generating stations any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State Government in a transparent manner, in case of existing projects proportionate cost of land being used for generating power from renewable sources, and any consumer contribution or grant received from the Central or State Government or any statutory body for execution of project, which does not include any repayment liability.

4.1.13 For the purpose of protecting consumer interests and as an added step for due diligence the commission may disallow any Capital Expenditure in the book entries which are not in accordance with the Capital Expenditure approved under the Regulations. Further, the Commission may undertake a prudence check taking into consideration the benchmark norms as may be specified by the Commission from time to time. This process can be independent of the Tariff determination process and as the Commission may deem appropriate on case-to-case basis. In cases where benchmark norms have been satisfied the Petitioner shall submit reasons for exceeding the capital cost from benchmark norms to the satisfaction of the Commission.

4.1.14 The Petitioner needs to submit the details of Capital Cost for execution of the existing and new projects as per formats specified/to be specified by the Commission from time to time along with tariff petition for the purpose of creating a database of benchmark capital cost of various components.

4.1.15 The Commission in order to safeguard the consumer interests may get the capital cost of any project vetted by an independent agency or an external expert and the same will only be considered as a guiding principle for the Commission to improve the transparency and decision-making process.

4.1.16 Accordingly, it is proposed that all the utilities need to acquire the approval for the Capital Investment Scheme at the time of Tariff determination. For this, the utilities need to submit the required documents for in-principle approval of capital expenditure as and when requested by the Commission throughout the process of approval. These documents for proper financial due diligence must include a Capital Investment Plan **as per the procedure which the Commission may specify from time to time**. The step is taken to ensure that there is a need for the major investment in Generation/ Transmission/ Distribution system which the applicant proposes to undertake.

4.1.17 As per the existing regulation, the True-up process takes place for each financial year and the Applicant needs to submit the Capital Investment Plan to be approved by the Commission as part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period. With a view to further regularize and streamline the filing and approval process of Capital Investment Schemes, a need is felt for developing a comprehensive Capital Investment Plan approval process, covering various aspects including threshold limit for prior approval, process of submission for approval, details required for prudence check, defining framework for approval of Schemes, need for approval of completed cost, etc. The Petitioner may apply for In-principle approval of DPR Schemes once in every quarter of each financial year and any filings done after the end of financial quarter will be considered along with the filings of the next quarter. This step expedites the process ensuring the Applicant doesn’t have to wait for an entire financial year to file for approval from the Commission.

4.1.18 The Capital Investment Plan shall be planned considering 3-5 year investment horizon for Generation and Transmission related investments and 1-3 year horizon for Distribution and SLDC related investments.

4.1.19 The Commission observes that the different utilities under distribution, generation or transmission, have varying average capitalization approved in the past 5 years from FY 2017-18 to FY 2021-22. Some of the distribution utilities such as PGVCL has an average capitalization approved as high as Rs 1541.298 Crore in the past 5 years and similarly MGVCL has an average approved capitalization as low as Rs 373.31 Crore. Similarly, for generation utilities GSECL has an average approved capitalization of Rs 1208.54 Crore compared to TPL-G (A) which has an average approved capitalization of Rs 24.584 Crore in the past 5 years. Further for the transmission utilities GETCO has an average approved capitalization of Rs 2256.58 Crore in the past 5 years, whereas SLDC has an average approved capitalization of Rs 345.29 Crore in the past 5 years. On studying the average capitalization costs of all the utilities in the past 5 years, the Commission found out that except for the SEZs, all the other utilities had an average capitalization costs equals or exceeds investment of Rs. 15 Crore for Generation and Transmission Businesses, Rs. 10 Crore for Distribution Business and Rs. 0.50 Crore for SLDC, hence all the Licensee should submit DPR for the Commission’s In-Principle Approval with a broad Cost-Benefit Analysis for the schemes with value above the limit as defined above.

4.1.20 For the purpose of In-principle approval of the Capital Investment Schemes above Rs. 20 Crore for Transmission and Rs. 15 Crore for Generation and Rs. 10 Crore or 0.5% of approved closing GFA of previous trued-up year for Distribution Licensees and subsequently Rs. 0.5 Crore for SLDC, the utilities are required to submit Detailed Project Report with Cost-Benefit Analysis. Capital schemes below the values specified above shall be considered as Non-DPR Schemes. This step is necessary to ensure that the process is streamlined and simplified to reduce the time for approvals and reduce the burden on the Commission for approval of small investment projects. The Capitalisation under Non-DPR Schemes shall be limited to 20% of total capital expenditure undertaken by the utilities in a control period and will not require a prior approval. Further, the Petitioner has to mandatorily ensure that the Capital Investment Schemes proposed should be for entire independent system and should not be submitted in parts in order to avoid filing DPR for projects that exceed the threshold for Non-DPR Schemes.

4.1.21 The Commission deems it appropriate that the limit of 20% of cumulative capital expenditure is enough for the Utilities to carry out the activities without any hinderances. Further, the Commission may approve for each year of the Control Period an additional amount of 20% of the total capital expenditure for that year towards planned or unplanned capital expenditure for which DPR is yet to be approved. However, in order to avoid double accounting, it is proposed to add a proviso to specify that Generating Company, Licensee and SLDC should ensure that expenses that would normally be classified as O&M expenses are not categorised under non-DPR schemes. In order to have clear demarcation of activities, it is also proposed to add a proviso to specify the list of activities that can be undertaken under O&M, separately for Generation Business, Transmission Business and Distribution Business, based on a separate study and after public consultation at a further point in time. Also, while calculating 20% limit for Non-DPR schemes capitalization under central or state grants should not be considered as part of cumulative capitalization.

4.1.22 Prior In-principle approval is not required for schemes where 100% of the funding is through Grants or Schemes with emergency works nature. In case of emergency works, the Petitioner needs to intimate the Commission within 15 days from start of work and DPR needs to be submitted for approval after the work begins. This step is important for ensuring system reliability and maintain power supply for the customers the same is subject to 20% of total capital expenditure approved for that year.

4.1.23 For schemes that are funded through Central or State grants or Conditional Schemes where the grant is allotted on the fulfillment of the conditions laid out, the utilities are required to intimate the Commission about these schemes with the necessary details and documentary evidences prior to the start of works. Further, the conditional schemes will be considered as a grant funded capex only and the fulfillment of the conditions will be under the purview of the utilities failing which they have to bear the cost related to these schemes.

4.1.24 The DPR shall contain the outline of the scope and objective of the proposed project explaining how the project meets the evaluation criteria mentioned. The DPR must include details such as technical reports, vendor quotations, audited financial statements, design criteria, etc. as and may be required to enable the assessment and safeguard the customer interests while ensuring the viability of the project. The Commission from time to time may also lay down the submission formats of DPR to facilitate assessment.

4.1.25 Evaluation criteria to be adopted for In-principle approval before the implementation of capital works is added to provide an initial approval of the Commission based on examination of the necessary techno-commercial feasibility of the project, containing proposed scope of work so that the Power Utility can begin the execution of work.

4.1.26 The evaluation criteria at the time of In-principle approval are as follows:

a) *Safety Requirement:* To ensure that all necessary obligations are being met as per Electricity Act, 2003, Section 6, Regulation 6.9 of Gujarat Electricity Grid Code,2003 and to highlight any statutory violation along with steps taken to safeguard the same, provided appropriate sanctions of competent authority and clearances from concerned departments/ministries is available.

b) *Necessity for the Investment*: To determine if it's needed to make the Capital Investment in infrastructure to meet current and future needs, to check if the equipment is operating as intended, or extend the lifespan of existing assets for a more reliable system and improved efficiency as may be applicable. It is an important step to ensure if the facility is being created as a multiple use asset or an existing asset can fulfill the function being served by the proposed utility.

c) *Bill of Material and Project Costing estimation*: This is a necessary step to ensure the correctness of the cost etc. and to maintain consistency amongst the proposed technical drawings, single line diagrams, Grid maps of the concerned areas and applicable standards from competent authorities such as Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 are adhered to. The BoQ, hence, needs to be complete in all aspects such as equipment/asset quantities, description, specification, supplier information etc.

d) *Cost Benefit Analysis:* The proposal should quantify the benefits of the Capital Investment scheme such as reduction in losses, access to new customers, reliability of supply, and any other benefit. This step acts as an important safeguard to ensure the Return on Investment is justifiable from the consumer's point of view. The utilities should also provide the methodology used for calculating the benefits to ensure consistency across the utilities.

e) *Evaluation of Alternatives and Constraints*: To ensure that the petitioner has considered alternative approaches, the Petitioner should justify the basis on which proposed scheme has been selected out of the alternatives considered to ensure the least cost plan with maximum benefit has been proposed. For example assessment of the fact that whether the scheme can be carried out under Operational Expenditure Scheme or O&M Budget. This step also needs the Applicant to ensure that all the constraints in proposed scheme have been envisaged and mitigation methods are prepared.

f) *Risk Analysis*: A scheme level detailed risk analysis matrix is necessary to be submitted depending on the value and criticality of the project. The risks to consider may include but are not limited to design, procurement, financing, RoW, construction etc. This ensures alternatives and associated risks have been evaluated during the planning process.

g) *Project Monitoring Mechanism & Execution Timelines*: Any foreseeable delay due to certain project risks must be incorporated within the DPR during the planning phase to account for scheduling, pre-award activities and avoid time and cost over-runs. Documents such as PERT Chart/Gantt Chart etc. showing completion stages and to assess whether alternative plans for delays have been evaluated.

h) *Technical Justification*: The step ensures that the scheme meets the design criteria in keeping with prevailing norms and standards and that the useful life of assets has been assumed correctly. This also ensures that sufficient steps have been taken to accommodate for the projected growth in demand and rate of obsolescence of technology.

i) *Quantifiable Customer Benefits*: A detailed scrutiny of the fact that the perceived customer benefits are quantifiable and verifiable and necessary data, justification and documentary evidence with methodology adopted for calculation has been specified.

4.1.27 At the stage of 'In-Principle' approval, the proposed cost by the Utility is an estimation hence it should be noted that In-principle should not be considered as final approval for ARR purpose. The final approval of capital expenditure will be granted at the time of True-up after prudence check and verification of actual cost, actual quantity of material used and verification of all Legal Clearances such as Environment Clearance, Forest Clearance, etc. Hence, final approval of completed cost after asset commissioning will be provided with the claim for true-up for any financial year in accordance with the GERC MYT Regulations applicable at that point of time.

4.1.28 The Petitioner needs to submit the list of all capital investment schemes planned to be undertaken for a financial year on or before 120 days from the start of the respective financial year with only those Schemes forming the part of ARR which have been approved by the Commission prior to the start of financial year for example for a capital investment scheme planned to be undertaken on 31st March 2024 the list of the capital investment scheme should be provided to the Commission by 30th November 2024. The Commission has decided to mandate the submission of DPR Schemes through the Capital Expenditure Approval Framework from second year of the Control period while the ongoing and projected Schemes for the first year of the Control Period need to seek a post-facto approval in accordance with capital expenditure approval framework.

4.1.29 The Commission has also considered the points brought forth in the Draft Electricity (Amendment) Rules, 2023 as mentioned below, where certain prudent costs incurred by the Distribution Licensees shall be pass-through:

"20 (I) Framework for financial Sustainability:

(d) All the prudent cost incurred by the Distribution licensee for creating the assets for development and maintenance of distribution system in accordance with sub-section (1) of section 42 of the Act shall be pass-through;

Provided that such pass-through of the cost for the assets created by the distribution licensee shall be subject to following conditions:

i) Asset has been created in accordance with the capex roll out plan for the licensee approved by the respective State Commission.

ii) Asset has been procured in competitive and transparent manner.

iii) Asset are geo-tagged and properly recorded in Fixed Asset Register (FAR) and the details are made available on the website of the Distribution licensee"

The Commission is of the view that this rule can help in simplifying the process for licensees for creating assets for development and maintenance of distribution systems. Therefore, the Commission proposes that all the Utilities must provide a time-bound plan to undertake geo-tagging in phased manner and access of the details of geo-tagging along with MYT petition for assets capitalized as on April 01, 2024.

4.1.30 Further, for existing Distribution Licensees supplying in SEZs, SIRs, Ports and new Distribution Licensees, the Commission has observed that the licensees take time to achieve considerable asset loading but they recover the entire costs related to the capital investment undertaken which burdens the consumers. To mitigate this, the Commission has proposed recovery of expenses attributable to the capitalized assets on pro-rata basis till the asset loading attains forty (40) percent. The unrecovered portion of expenses will be deferred without any interest cost.

4.1.31 The capital cost for all the assets that were used for a period of time for unregulated activities or have been included in the asset base after the Date of Commercial operation or the asset has not been put to use after COD for the regulated business will be considered only after deduction of accumulated depreciation till that point in time.

4.1.32 The Petitioner shall provide a copy of the proposed Capital Investment Plan for

Generation and/or Distribution Business, as the case may be, to the State Transmission Utility for carrying out planning for network augmentation/strengthening at the time of filing of the plan with the Commission. The copy of approved Capital Investment Plan should also be sent to STU, immediately after Commission's approval.

4.1.33 The prior In-principle approval granted by the Commission is subject to Appeal before higher Courts in same manner as any other order for Capital Investment issued by the Commission to improve transparency in the Capital Investment approval process.

4.1.34 GERC MYT Regulations, 2016 did not have the ceiling limits for initial spares capitalised as a percentage of the Plant and Machinery cost up to cut-off date of Static Synchronous Compensator the same have been added in the draft GERC MYT Regulations, 2023 and the ceiling limit has been kept at 6.00% for the same.

4.1.35 For the calculation of net value of replaced assets the Commission shall consider the cost of replaced asset on case-to-case basis if the original cost of the replaced asset is not available. The amount of insurance proceeds received towards the damage to any asset shall be adjusted towards outstanding actual or normative loan and any balance amount after being utilized for reduction of the capital cost of such replaced asset shall be considered as Non-Tariff Income.

4.1.36 The factors to be considered at the time of true-up are the extent to which the scope and objectives at the time of In-principle approval have been achieved, actual benefits and results achieved and whether competitive bidding prices have been followed by the utility.

Final Draft Regulation

4.1.37 In view of the discussion in the foregoing paragraphs, the Commission proposes the following provision for Capital Cost in the draft Regulations:

"29 Capital Cost

29.1 In case of existing projects, the capital cost admitted by the Commission prior to April 01, 2024 and the additional capital expenditure projected to be incurred for the respective year of the Control Period, as may be admitted by the Commission, shall form the basis for determination of tariff.

29.2 The Capital Cost for a new project shall include:

(a) expenditure incurred or projected to be incurred upto the cut-off date, including interest during construction, financing charges and incidental expenditure during construction, up to the date of commercial

operation of the project, as admitted by the Commission after prudence check;

(b) capitalised initial spares subject to the ceiling rates specified in these Regulations;

(c) expenditure on account of additional capitalisation as determined in accordance with Regulation 30 of these Regulations;

(d) any gains or losses on account of foreign exchange rate variation pertaining to the loan amount availed up to the cut-off date, as admitted by the Commission after prudence check:

Provided that any gains or losses on account of foreign exchange rate variation pertaining to the loan amount availed up to the date of commercial operation shall be adjusted only against the debt component of the capital cost:

Provided also that the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall submit documentary evidence in support of its claim of assets being put to use:

Provided also that the Commission may undertake a verification to check if the assets are put to use as submitted by the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, independent of the tariff determination process.

29.3 Capital cost in case of existing or new hydro Generating Station shall also include 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.

29.4 Following shall be excluded from the capital cost of the existing and new projects:

(a) The assets forming part of the project, but not put to use or not in use, as declared in the tariff petition;

(b) De-capitalised assets after the date of commercial operation on account of replacement or removal on account of obsolescence or shifting from one project to another project:

(c) In case of hydro generating stations, any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State Government by following a transparent process;

(d) Proportionate cost of land of the existing project which is being used for generating power from renewable sources; and

(e) Any consumer contribution or grant received from the Central or State Government or any statutory body or authority for the execution of the project, which does not carry any liability of repayment;

(f) Any capitalisation done by mere book entries / presentation in the financial statements in order to comply with any statute / rules etc. and not in accordance with the Capital Expenditure approved under these Regulations.

29.5 Capital cost admitted by the Commission after prudence check shall form the basis for determination of tariff:

Provided that in case of Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, prudence check of capital cost may be carried out taking into consideration the benchmark norms specified/to be specified by the Commission from time to time;

Provided further that in cases where benchmark norms have been specified, Generating Company or Transmission Licensee or SLDC or Distribution Licensee shall submit the reasons for exceeding the capital cost from benchmark norms to the satisfaction of the Commission for allowing cost above benchmark norms;

Provided also that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, use of efficient technology, competitive bidding, cost over-run and time overrun, and such other matters as may be considered appropriate by the Commission for determination of tariff.

29.6 Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall furnish the details of capital cost for execution of the existing and new projects as per formats specified/to be specified by the Commission from time to time along with tariff petition for the purpose of creating a database of benchmark capital cost of various components.

29.7 The Commission may get the capital cost of any project vetted by an independent agency or an external expert. However, the same shall be considered as one of the guiding factors only and shall not be binding on the Commission.

29.8 The Commission has specified the Guidelines for approval of Capital Investment Schemes as provided in Annexure III of these Regulations. Generation Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall make an application to the

Commission for obtaining prior approval of the Commission for schemes involving major investments as per criteria specified in these Guidelines.

29.9 Capital cost to be allowed by the Commission for the purpose of determination of tariff for respective businesses will be based on the Detailed Project Reports (DPRs) and Capital Investment Plan as approved by the Commission from time to time:

Provided that the capital investment plan shall contain the scheme details, justification for the work, capitalization schedule, capital structure and cost benefit analysis (wherever applicable):

Provided further that Capital cost considered by the Commission in the MYT Orders shall not be termed as "In-principal approval" and the same shall be governed by the provisions of Annexure III of these Regulations.

29.10 Generation Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall submit the Detailed Project Reports (DPRs) for all the schemes which shall include:

(a) Scope and Objective;
(b) Purpose of investment;
(c) Broad Technical Specifications of the proposed investment and supporting details;
(d) Capital Structure;
(e) Capitalization Schedule;
(f) Financing Plan, including identified sources of investment;
(g) Physical targets;
(h) Cost-benefit analysis;
(i) Prioritization of proposed investments:

Provided that DPRs will not be necessary for schemes below the threshold level as provided in the Guidelines for Capital Investment Plan annexed as Annexure III of this Regulations:

Provided further that DPRs will not be necessary for schemes funded through Central or State Grant or through Consumer Contribution or through Deposit works. However, Generation Company or Transmission Licensee or SLDC or Distribution Licensee shall be required to intimate the Commission prior to the execution of such schemes:

Provided that Generation Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall be required to ensure that the procurement of the assets have been undertaken in a competitive and transparent manner. Further, the assets so capitalized as a part of the approved capital investment plan under these Regulations should *necessarily be geo-tagged and properly recorded in Fixed Asset Register (FAR) for allowance of the capitalization of the same by the Commission:*

Provided that regarding the assets already capitalized as on April 01, 2024, Generation Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall prepare and submit to the Commission a time-bound plan to undertake the geo-tagging in phased manner, preferably within the Control Period, along with the MYT Petition:

Provided further that Generation Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, must provide access of the details of geo-tagging to the Commission for online monitoring.

29.11 Approved capital cost shall be considered for determination of tariff and any escalation in the capital cost for which sufficient justification is provided may be considered by the Commission subject to prudence check:

Provided that in case the actual capital cost is lower than the approved capital cost, then the actual capital cost will be considered for determination of tariff of Generating Company, Transmission Licensee, SLDC and Distribution Licensee.

29.12 Capital cost of the assets related to unregulated business being transferred to regulated business shall be considered after deducting the amount of accumulated depreciation, computed till the period of asset utilisation for unregulated business or for the period for which the assets remained unutilised, for the purpose of tariff determination, in the following instances:

(a) The asset/s have been used for a period of time for unregulated business or the asset/s have become part of the asset base of the regulated business after lapse of time with respect to the COD of the asset;

(b) If the asset has not been put to use for the regulated business after COD.

29.13 Actual capital expenditure as on COD for the original scope of work may be considered based on audited accounts of Generating Company or Transmission Licensee or SLDC or Distribution Licensee, limited to original cost and subject to prudence check by the Commission.

29.14 The Commission may approve, an additional amount up to 20% of the total capital expenditure approved for that year, towards planned or *unplanned capital expenditure for which DPR is yet to be approved by the Commission.*

29.15 The cumulative amount of capitalisation against non-DPR schemes for any year shall not exceed 20%, of the cumulative amount of capitalisation approved against DPR schemes for that Year:

Provided that the capitalisation under schemes funded through Central or State grant or through Consumer Contribution or through Deposit works shall not form part of the above-mentioned limit of 20% of the cumulative capitalisation:

Provided further that Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, should ensure that expenses that would normally be classified as O&M expenses are not categorised under non-DPR schemes.

29.16 In case of existing Distribution Licensees supplying in SEZs, SIRs, Ports and new Distribution Licensees, recovery of expenses attributable to the capitalized assets, i.e. depreciation, interest on loan, RoE and / or RoCE shall be allowed on pro-rata basis till the asset loading attains forty (40) percent, while the unrecovered portion of expenses will be deferred without any carrying cost.

29.17 Generating Company or Distribution Licensee shall provide a copy of the proposed Capital Investment Plan for Generation and/or Distribution Business, as the case may be, to the State Transmission Utility (STU) for carrying out planning for network augmentation/ strengthening at the time of filing of this plan with the Commission. The copy of approved capital investment plan shall also be sent to the STU, immediately after approval by the Commission.

29.18 Where the power purchase agreement or bulk power transmission agreement provides for a ceiling of capital cost, the capital cost to be considered shall not exceed such ceiling.

29.19 Revenue earned from sale of infirm power in excess of fuel cost prior to the COD as specified under Regulation 51 of these Regulations, shall be adjusted against the Capital Cost.

29.20 Capital cost may include initial spares capitalised as a percentage of the Plant and Machinery cost upto cut-off date, subject to following ceiling norms:

(a) Coal-based/lignite-fired thermal generating stations - 4.0 %

(b) Gas Turbine/Combined Cycle thermal generating stations - 4.0 %

(c) Hydro generating stations including pumped storage hydro generating station - 4.0 %

(d) Transmission system and Distribution System

(i) Transmission Line & Distribution Line - 1.0 %

(ii) Transmission Sub-station & Distribution Sub-station (Green Field) - 4.0 %

(iii) Transmission Sub-station (Brown Field)- 6.0 %

(iv) Series Compensation devices and HVDC Sub-station- 4.0 %

(v) Gas Insulated Sub-station (GIS)- 5.0 %

(vi) Communication System- 3.5 %

(vii) Static Synchronous Compensator- 6.0 %

29.21 The impact of revaluation of assets shall be permitted during the Control Period, provided it does not result in increase in tariff of Generating Company, Transmission Licensee, SLDC or Distribution Licensee:

Provided that any benefit from such revaluation shall be passed on to persons sharing the capacity charge in case of a Generating Company, or to long-term Intra-State open access customers of Transmission Licensee or Distribution Licensee, or retail supply consumers in case of Distribution Licensees, at the time of Multi-Year Tariff determination, or Mid-term Review or Truing up, as the case may be.

29.22 Any expenditure on replacement, renovation and modernization or extension of life of old fixed assets, as applicable to Generating Company, Transmission Licensee, SLDC or Distribution Licensee, shall be considered after writing off the net value of such replaced assets from the original capital cost and will be calculated as follows:

Net Value of Replaced Assets = OCRA – AD –G/CC;

Where;

OCRA: Original Capital Cost of Replaced Assets;

AD: Accumulated depreciation pertaining to the Replaced Assets;

G/CC: Total Grants or Consumer Contribution pertaining to the Replaced Assets:

Provided that, in case the original capital cost of the replaced asset is not available for any reason, it shall be considered by the Commission on a case to case basis:

Provided further that the amount of insurance proceeds received, if any, towards damage to any asset requiring its replacement shall be first adjusted towards outstanding actual or normative loan; and the balance amount, if any, shall be utilised to reduce the capital cost of such replaced *asset, and any further balance amount shall be considered as Non-Tariff Income.*

Explanation – For the purpose of this Regulation, the term 'renovation and modernisation' shall have the same meaning as in Section 80 IA of the Income-Tax Act, 1961.

4.2 Additional Capitalisation

Suggestion/Comment from Stakeholders:

4.2.1 FOKIA has commented that they have observed in the past that large numbers of lines and substations remain grossly underloaded, resulting in avoidable cost capitalization and increase in the transmission tariffs to no avail. Hence it would be desirable that the Commission decides the Norms for undertaking capacity augmentation of the Sub-station and for strengthening of lines so as to avert under-utilization of the capacity and CAPEX for such assets.

Commissions View

4.2.2 The Commission after due considerations of all the comments received has the following views.

4.2.3 Regulation 35 of the GERC MYT Regulations, 2016 specifies provisions of additional capitalization under following three categories, viz.,

a) capital expenditure within the original scope of work, after the date of commercial operation and up to the cut-off date;

b) capital expenditure in respect of a new Project within the original scope of work after the cut-off date;

c) capital expenditure after the cut-off date.

4.2.4 It is also proposed to add a requirement that additional capital expenditure on account of ‘change in law’ or ‘Force Majeure’ events be included since the matters pertaining to Change in Law and Force Majeure events have been filed for petitions for approval by Generating Companies or Licensees. These are considered uncontrollable in nature and have been a critical factor which increases the capital cost and contributes to time over-run of projects. Therefore, the Commission is of the view to allow time and cost over runs on account of change in law and force majeure except where the delay is attributable to the Generation Company or Transmission/Distribution Licensee or SLDC. Accordingly additional sub-clause as Regulation 30.1.1 (vi) is proposed.

4.2.5 The Commission observed that CERC in its Tariff Regulations, 2019 has clearly defined the additional capitalisation within the original scope and upto cut-off date, additional capitalisation within original scope and after cut-off date, and additional capitalization beyond the original scope. CERC has also introduced provision for Additional Capitalisation on account of revision of emission standards. It is proposed to adopt the same approach followed by CERC. Hence, appropriate provisions have been added in the draft GERC MYT Regulations, 2023.

4.2.6 The additional capital expenditure on account of force majeure events were not mentioned in the existing Regulations. The CERC has included the same in its Tariff Regulations, 2019 as the additional capital expenditure may be incurred due to force majeure event which is uncontrollable in nature and is required to be undertaken for smooth operation of the Generating Company, Transmission Licensee, SLDC or Distribution Licensee. Accordingly, the same is proposed to be included in the Regulations by the Commission as an enabling clause to undertake the Additional Capital Expenditure.

4.2.7 CERC has also added provisions with respect to additional capitalization, in case of replacement of asset or equipment is necessary on account of obsolescence of technology. Further, taking cognizance of the Tariff Policy, 2016 which mandates use of treated sewage water by TPPs located within 50 km radius of sewage treatment plant, the CERC has added appropriate provision in its Tariff Regulations. Accordingly, in line with the National Tariff Policy 2016 and approach adopted by the CERC, it is proposed that any existing thermal generating units would be allowed to have a sewage water treatment plant for usage of water and the expenditure against the same will be allowed as additional expenditure after prudence check.

4.2.8 The Commission has deemed it appropriate that the approval of additional capital expenditure beyond the cut-off date for activities within the original scope be subject to submission of report on impact assessment done by any reputed third party technical expert/agency on the benefits realized from previous investments under this head in last five years.

Final Draft Regulation

4.2.9 After perusal of the CERC Tariff Regulations, 2019, the Commission has proposed the following provisions for Additional Capitalisation in the draft GERC MYT Regulations, 2023:

"30 Additional Capitalisation

30.1 Additional Capitalisation within the original scope and upto the cut-off date:

30.1.1 Capital expenditure, actually incurred or projected to be incurred, in respect of new project or an existing project, on the following counts within the original scope of work, after the date of commercial operation *and up to the cut-off date may be admitted by the Commission, subject to prudence check:*

(i) Undischarged liabilities recognized to be payable at a future date;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Regulation 29.19 of these Regulations;

(iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(v) Change in law or compliance of any existing law; and

(vi) Force Majeure events:

Provided that in case of any replacement of the assets, the additional capitalization shall be worked out after adjusting the gross fixed assets and cumulative depreciation of the assets replaced on account of de-capitalization:

Provided that the details of works asset-wise/work-wise included in the original scope of work along with estimates of expenditure, liabilities recognized to be payable at a future date and the works deferred for execution shall be submitted along with the Petition for determination of tariff after the date of commercial operation of the Generating Unit/Station or Transmission system.

30.2 Additional Capitalisation within the original scope and after the cut-off date:

30.2.1 Capital expenditure incurred or projected to be incurred in respect of the new project on the following counts within the original scope of work after the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of direction or of any statutory authority or order or decree of a court of law;

(ii) Change in law or compliance of any existing law;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work;

(iv) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments, etc.

(v) Force Majeure events;

(vi) Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;

(vii) Any additional capital expenditure which has become necessary for efficient operation:

Provided that the claim shall be substantiated with the technical justification duly supported by documentary evidence like test results carried out by an independent agency in case of deterioration of assets, damage caused by natural calamities, obsolescence of technology, up-gradation of capacity for the technical reason such as increase in fault level:

Provided further that the approval of additional capital expenditure for efficient operation shall be subject to submission of report on impact assessment done by any reputed third-party technical expert/agency on the benefits realised from previous investments under this head in the last five years;

(viii) Raising of ash dyke as a part of ash disposal system.

Provided that in case of replacement of assets deployed under the original scope of the existing project after cut-off date, the additional capitalization may be admitted by the Commission, after making necessary adjustments in the gross fixed assets and the cumulative depreciation, subject to prudence check on the following grounds:

(a) Useful life of the assets is not commensurate with the useful life of the project and such assets have been fully depreciated in accordance with the provisions of these Regulations;

(b) Replacement of the asset or equipment is necessary on account of change in law or Force Majeure conditions;

(c) Replacement of such asset or equipment is necessary on account of obsolescence of technology; and

(d) Replacement of such asset or equipment has otherwise been allowed by the Commission.

30.3 Additional Capitalisation beyond the original scope of work:

30.3.1 Capital expenditure, in respect of existing Generating station or Transmission system including communication system, incurred or projected to be incurred on the following counts beyond the original scope of work, may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(ii) Change in law or compliance of any existing law;

(iii) Force majeure events;

(iv) Any expenses to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Government Agencies or statutory authorities responsible for national security/internal security;

(v) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.;

(vi) Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;

(vii) Usage of water from sewage treatment plant in thermal generating station:

Provided that any expenditure, which has been claimed under Renovation and Modernisation or repairs and maintenance under O&M expenses, shall not be claimed under this Regulation;

(viii) Any additional capital expenditure which has become necessary for efficient operation of generating station other than coal/ lignite based stations or transmission system as the case may be. The claim shall be substantiated with the technical justification duly supported by the documentary evidence like test results carried out by an independent agency in case of deterioration of assets, report of an independent agency in case of damage caused by natural

calamities, obsolescence of technology, up-gradation of capacity for the technical reason such as increase in fault level;

(ix) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) and due to geological reasons after adjusting the proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation;

(x) In case of transmission system, any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement due to obsolesce of technology, replacement of switchyard equipment due to increase of fault level, tower strengthening, communication equipment, emergency restoration system, insulators cleaning infrastructure, replacement of porcelain insulator with polymer insulators, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system; and

(xi) Any capital expenditure found justified after prudence check necessitated on account of modifications required or done in fuel receiving system arising due to non-materialisation of coal supply corresponding to full coal linkage in respect of thermal generating station as result of circumstances not within the control of the generating station:

Provided that any expenditure on acquiring the minor items or the assets including tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, computers, fans, washing machines, heat convectors, mattresses, carpets, etc., bought after the cut-off date shall not be considered for additional capitalization for determination of tariff w.e.f. April 01, 2024:

Provided further that if any expenditure has been claimed under Renovation and Modernisation or repairs and maintenance under (O&M) expenses, same expenditure cannot be claimed under this Regulation.

30.4 Additional Capitalization on account of Revised Emission Standards:

30.4.1 A Generating Company requiring to incur additional capital expenditure in the existing generating station for compliance of the revised emissions standards, may be admitted by the Commission, subject to prudence check based on the following details to be submitted by the Generating Company:

(i) details of proposed technology as specified by the Central Electricity Authority or alternative technology based on appropriate justification;

(ii) scope of work;

(iii) phasing of expenditure;

(iv) schedule of completion;

(v) estimated completion cost including foreign exchange component, if any;

(vi) detailed computation of indicative impact on tariff to the beneficiaries; and

(vii) any other information considered to be relevant by the Generating Company:

Provided that the Commission may grant approval after due consideration of the 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.

30.5 In case of de-capitalisation of assets of a Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, the original cost of such asset as on the date of decapitalization shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place with corresponding adjustments in cumulative depreciation and cumulative repayment of loan, duly taking into consideration the year in which it was capitalised.

Provided that the de-capitalization of the old asset for the purpose of tariff, is affected from the very same year in which the capitalization of the new asset is allowed, irrespective of its actual de-capitalization in the *books of accounts of the Generating Company, Transmission Licensee, SLDC or Distribution Licensee, as the case may be.*

Provided that in case the original cost of the de-capitalised asset is not available, the Commission shall consider the same by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset."

4.3 Debt-Equity Ratio

4.3.1 Capital expenditures undertaken by Licensees and Generation Companies should be made at an optimal debt:equity ratio to balance the necessity for generating appropriate returns that can be earned by Licensees and Generation Companies while also preserving consumers' interests.

4.3.2 The GERC MYT Regulations, 2016, assumes a normative debt to equity ratio of 70:30 for a project. The existing regulations considers the GFA (Gross Fixed Asset) Approach under the legislation, in which the returns are given on a normative basis on the normative equity base, i.e. 30% or actual equity base, whichever is lower, until the asset is utilized.

4.3.3 The interest on loan, which is a component of the yearly fixed cost, is calculated based on the weighted average rate of interest as per the project's actual loan portfolio. The current practice for permitting debt repayment is to allow depreciation equating to 90% of 70% of capital investment over the first 12 years, while the remaining capital is depreciated throughout the asset's residual life.

4.3.4 The present GFA approach was chosen because it is seen to be vital to boost potential investment in the power industry, as well as to motivate utilities to continue operating old assets that are still in outstanding shape after their initial useful life has expired. This also has the advantage of reduced fixed costs because there is no or very little debt to pay and the equity component is at a historical cost, which is significantly less than the current replacement cost.

4.3.5 There are two other types of approaches (other than Gross Fixed Asset (GFA) Approach) to calculate the Return on Equity (RoE) for any asset, as shown below:

a) Modified Gross Fixed Asset (GFA) Approach: This method employs a hybrid or modified GFA approach, in which the depreciation recovery in the early years is used to repay the loan and is then applied to the equity. As a result, at the end of the asset's useful life, the leftover equity component equals the salvage value of the asset.

b) Return on Capital Employed (RoCE) Approach: This approach includes calculating the total return by applying the Weighted Average Cost of Capital (WACC) to an asset base. It is the most extensively utilized approach by regulators worldwide. The ROCE approach considers various aspects, including asset age, extra capitalization in schemes, project debt-equity ratios, and so on. The WACC is calculated using the following formula in this method:

WACC= (D/V)*Kd+ (E/V)*Ke

Where,

D = Normative Debt

E = Normative Equity

V = Total Capital i.e., Sum of Debt & Equity

Kd = Cost of Debt

Ke = Cost of Equity

4.3.6 The RoCE or NFA approach allows for the adjustment of both debt and equity from depreciation in a proportional approach right from the start. By the end of its useful life, an asset recovers approximately 90% of its invested capital in the form of depreciation.

4.3.7 The Central Electricity Regulatory Commission in their 2019 Tariff Regulations proposed that, the existing GFA approach of giving a return on investment for existing projects may be sustained up to the end of their original useful life. The Modified GFA Approach would be applicable once the original useful life of the different projects was completed. In the case of new projects, the Commission is now considering using the Modified GFA Approach after the initial useful life has expired. Furthermore, beginning on April 1, 2024, the Modified GFA Approach will be applied to existing projects that have reached the end of their original useful life.

4.3.8 The Commission clarified that for the purpose of applying Modified GFA Approach, the capital structure, i.e., GFA, debt and equity as on cut-off date shall be considered and any additional capital expenditure after the cut-off date, including that for R&M shall be adjusted separately.

4.3.9 CERC Commission further proposed clause (6) of the Regulation 17 in the draft notification issued on 14th December 2018:

"In case of generating station or a transmission system including communication system which has completed its useful life as on or after 1.4.2019, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for

reduction of equity till the generating station continues to generate and supply electricity to the beneficiaries."

Issues discussed in the Discussion Paper

4.3.10 The Consultation Paper had brought out the following issues:

Tariff Regulations based on the GFA Approach (including GERC MYT Regulations, 2016) do not include provisions for equity reduction after useful life conclusion. As a result, continuing to allow the return of existing equity base, i.e., 30% of capital expenditure, effectively implies permitting return on investment that has already been recovered.

4.3.11 There are several implementation options to consider using all the RoE approaches, including the following:

- Consider shifting to RoCE (NFA) approach for all assets, i.e., existing as well as assets commissioning in the new Control Period
- Consider shifting to RoCE (NFA) approach for assets commissioned w.e.f new Control Period, while maintaining existing assets under the RoE (GFA) approach only;
- Reduce equity to salvage value levels or normative equity levels for existing assets during the new MYT Control Period, and use the RoCE (NFA) approach for assets commissioned beginning with the new Control Period;

Suggestion/Comment from Stakeholders:

1) Adani Power Limited has submitted that the existing RoE approach has been followed by all regulatory commissions and it provides regulatory certainty to investors and therefore, has a strong case to be continued in next control period as well. They further explained that Hon'ble CERC has proposed to retain the RoE approach for the ensuing Control Period 2024-29 and submitted that the GERC may also continue the existing RoE approach in line with the approach proposed by Hon'ble CERC
2) MPSEZ Utilities Limited has requested Hon'ble Commission to allow RoE approach since the same has been followed by most of the Regulatory Commissions. Moreover, existing RoE approach provides regulatory certainty to investors and therefore has a strong case to be continued in next control period as well.
3) GSECL has submitted that in existing projects which are in operation, the present approach of RoE (GFA) should be continued. There are efficiency improvement projects being implemented in existing plants such as Wanakbori TPS Unit-1, 2 and Ukai Unit 3 & 5, and capital contribution in the form of equity may be required to be provided by GoG. Moreover, requirement of spares and increased maintenance

expenses for the old plants validates the need for RoE throughout the life of the project to keep the plants in good working conditions for a longer period. Moreover, it is also submitted that, for shifting to RoCE approach in case of the existing projects, the entire fixed cost calculations of existing projects need to be revised for balance useful life of the project considering IRR as more than RoCE (Cost of capital). Further, the cost of debt (Kd) consideration based on the weighted average cost of debt of the entire loan portfolio or benchmarking based on average cost of debt to business in a sector cannot be done, as the later keeps on fluctuating in Indian Debt market and could be different for different generators depending on various factors. In view of above, it is suggested to continue with existing approach of RoE (GFA) in existing projects.

4) Prayas Energy Group has submitted that shifting to the RoCE method for assets commissioned in the new control period will ensure the reflection of the benefits of this method, however adoption of the same for existent plants requires more consideration. Further, it is proposed that in order to reflect the advantage of the RoCE method for existent capacity, the equity of such projects could be reduced to salvage value/normative levels for the new MYT period. Towards its effective implementation, it is crucial to ensure prudence while designing RoCE and include revisions for each control period
5) GUVNL has submitted that huge investment is required to upgrade / strengthen distribution network for improving quality of power and consumer related services. It is submitted that the return earned by the utility is primarily used to fund the new capital expenditure for the benefits the consumers. Hence, any reduction in the return on equity earned by the utility will adversely impact the availability of equity for contributing to the new capital expenditure schemes.
6) GETCO has submitted that Transmission business at Intra-State level is still under growing phase and in this precarious market scenario, lenders have become risk averse to lend and business are suffering for the want of free cash flow and adequate credit facilities and therefore, have submitted to continue the present concept of RoE (GFA)
7) TPL has submitted that CERC approach of using existing RoE method should be followed on the subject of RoE Vs RoCE, as applicability of ROCE approach is not favored due to frequent variation in Interest Rates.

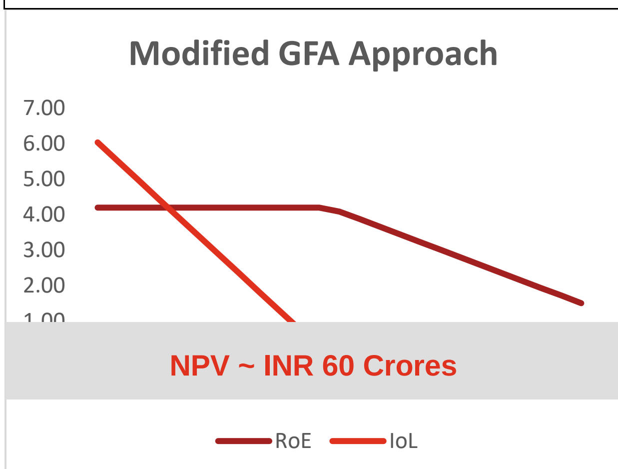
<u>Commission's View:</u>

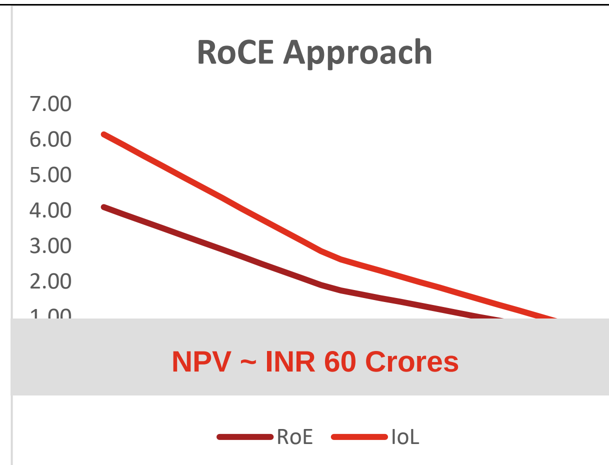
4.3.12 The Commission has noted the submissions made by various stakeholders regarding the Debt-Equity Ratio and have discussed its views in the following paragraphs.

4.3.13 The Commission proposes to maintain the current provision of a debt-to-equity ratio of 70:30 for tariff determination of Generation Companies, Transmission Licensees, and Distribution Licensees during the next Control Period, which is also in line with the provisions of the CERC Tariff Regulations, 2019.

4.3.14 Further, the Commission has analysed both the approaches i.e. Modified GFA Approach and RoCE Approach based on the scenario analysis as shown below:

Assumptions:
Capital Cost – INR 100 Crores | Debt to Equity Ratio – 70:30 | Return on Equity – 14% | Interest on Loan (IoL) – 9% | Loan Tenure – 12 years





4.3.15 The above analysis shows the relationship between the Return on Equity (RoE) and the Interest on Loan (IoL) for the two approaches over the useful life of the asset. From above, we can observe that:

i. For the Modified GFA Approach, RoE for the investors starts decreasing, after the loan is fully repaid.

ii. For the RoCE Approach, RoE for the investors keep decreasing along with the interest on loan over the useful life of the asset

iii. Further, both the approaches have a healthy NPV of around 60 crores (for loan tenure of 12 years)

4.3.16 For the existing projects, investors made investments based on the provisions of the then-current Tariff Regulations, and any change in the debt-equity ratio of such projects would create regulatory uncertainty.

4.3.17 Therefore, in order to ensure regulatory certainty and balance the interest of utilities and consumers, the Commission is inclined to consider the following approaches for the upcoming control period:

i. Shifting to RoCE (NFA) approach for assets commissioned w.e.f. new Control Period, while maintaining the existing assets under the RoE (GFA) approach only

ii. Reduce equity to salvage value levels gradually in five equal installments for the assets which has completed the useful life as on April 1, 2024, and use the RoCE (NFA) approach for assets commissioned beginning with the new Control Period

Final Draft Regulations

4.3.18 In view of the discussion in the foregoing paragraphs, the Commission proposes the following provision for Debt-Equity Ratio in the draft Regulations:

*"**32 Debt-Equity ratio***

32.1 Existing Projects: In case of a Generating Company, Transmission Licensee, SLDC and Distribution Licensee, if any fixed asset is capitalised on account of capital expenditure incurred prior to April 01, 2024, debt-equity ratio as allowed by the Commission for determination of tariff for the period ending March 31, 2024 shall be considered:

Provided that in case of a generating station or a transmission system or a communication system or a distribution system, which has completed its useful life as on or after 1.4.2024, the excess of accumulated depreciation net of cumulative repayment of normative loan attributable to such asset, shall be utilized for reduction of the equity over the period of next five financial years in equal tranches:

Provided also that depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan, if any and thereafter shall be utilized for reduction of equity:

Provided further that in case of de-capitalisation or retirement or replacement of assets, the equity capital approved for the said asset, shall be reduced to the extent of 30% (or actual equity component based on documentary evidence, if it is lower than 30%) of the original cost of the decapitalised or retired or replaced asset, and the debt capital approved as mentioned above, shall be reduced to the extent of actual debt component, based on documentary evidence, of the original cost of the de-capitalised or retired or replaced asset:

Provided further that the Commission shall not consider the increase in equity as a result of revaluation of assets (including land) for the purpose of computing return on equity:

Provided further that for the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee formed as a result of a Transfer Scheme, the date of the Transfer Scheme shall be the effective date for the determination of equity capital.

32.2 New Projects: In case of a Generating Company, Transmission Licensee, SLDC and Distribution Licensee, if any fixed asset is capitalised on account of capital expenditure incurred on or after April 01, 2024, for determination of Tariff the debt-equity ratio as on the date of commercial operation shall be considered on normative basis at 70:30 of the amount of capital cost approved by the Commission under Regulation 29 of these Regulations, after prudence check.

Provided that:

(i) where actual equity employed is more than 30% of capital cost approved by the Commission, the amount of equity for the purpose of tariff shall be limited to 30% and the balance amount shall be considered as normative loan:

(ii) where actual equity employed is less than 30% of capital cost approved by the Commission, the actual equity shall be considered, and the balance amount in excess of 70% normative loan shall also be considered as loan:

(iii) the equity invested in foreign currency shall be designated in Indian rupees based on the exchange rate prevailing on the date(s) it is subscribed:

(iv) any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of debt: equity ratio.

(v) Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall submit the resolution of the Board of the company or approval of the competent authority in other cases regarding infusion of funds from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure.

32.3 In case of Transmission Licensee or Distribution Licensee, the cost of project and accordingly debt equity ratio may be calculated considering the whole network of transmission or distribution system of the licensee, as the case may be, in place of individual line or project.

32.4 Any expenditure incurred or projected to be incurred on or after April 01, 2024, as may be admitted by the Commission as additional capital expenditure for determination of Tariff, and renovation and modernisation expenditure for life extension, shall be serviced in the manner specified in this Regulation."

4.4 Return on Capital Employed

4.4.1 The Return on Capital Employed (RoCE) is computed on the basis of the asset base for each year and the Weighted Average Cost of Capital (WACC). The Regulated Rate Base (RRB) shall be used to calculate the total capital employed which shall include the original cost of fixed assets, less the accumulated depreciation. Capital subsidies / grants shall be deducted in arriving at the RRB. 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 the corresponding capitalisation schedule.

4.4.2 The RoCE approach allows for the adjustment of both debt and equity from depreciation in a proportion right from the start. By the end of its useful life, an asset recovers approximately 90% of its invested capital in the form of depreciation.

4.4.3 Accordingly, the Commission has also proposed to introduce the following provision for Return on the Capital Employed for assets capitalizing all after 1st April 2024 in the draft Regulations:

"36 ***Return on Capital Employed in case of Assets capitalized on or after April 01, 2024***

36.1 In case of an asset being capitalized on or after April 01, 2024, Return on Capital Employed (RoCE) approach shall be used to provide a return to the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, and shall cover all financing costs except expenses for availing the loans, without providing separate allowances for interest on loans.

36.2 Regulated Rate Base (RBB) shall be used to calculate the total capital employed which shall include the Original Cost of Fixed Assets (OCFA) capitalized on or after April 01, 2024:

Provided that Capital Work in Progress (CWIP) shall not form part of the RRB:

Provided further that accumulated depreciation, consumer contribution, capital subsidies/ grants attributable to the fixed assets capitalized on or after April 01, 2024 shall be deducted in arriving at the RRB.

36.3 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 during the Control Period.

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

$RRBi = RRBi\text{-}1 + \Delta\ Abi / 2$

Where,

"i" is the ith year of the Control Period;

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

∆Abi: Change in Capital Investment in the ith year of the Control Period;

This component shall be arrived as follows:

$\Delta Abi = Invi – Di – CCi – Reti$

Where,

Invi: Investments projected to be capitalised during the 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, capital subsidy/grant pertaining to the ∆ABi and capital grants/ subsidies received during ith year of the Control Period for construction of service lines or creation of fixed assets;

Reti: Amount of fixed asset on account of Retirement/ Decapitalisation during ith Year;

RRBi-1: Closing Regulated Rate Base for the Financial Year preceding the ith year of the Control period. For the first year of the Control Period, Opening Regulated Rate Base i.e. RRB0 shall be ZERO.

36.5 All components for the computation of Regulated Rate Base and related components under these Regulations shall be based on the Fixed Assets capitalized on or after April 01, 2024.

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

$ROCE = WACCi \times RRBi$

Where,

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

RRBi is Average Regulated Rate Base for the ith year of the Control Period.

WACC for each year of the Control Period shall be computed in the following manner:

*WACC = ("D" /"D+E" ")" * rd + ("E" /"D+E" ")" * re*

Where,

D is the amount of Debt derived at the time of capitalisation as per these Regulations for the Fixed Assets capitalized on or after April 01, 2024;

E is the amount of Equity derived at the time of capitalisation as per these Regulations for the Fixed Assets capitalized on or after April 01, 2024;

Where equity employed is in excess of 30% of the capital employed (after deduction of grant, consumer contribution, if any), 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 excess equity shall be the weighted average rate of Interest on the actual loans for the regulated business of the Generating Station, Transmission Licensee, SLDC or Distribution Licensee, as the case may be, in accordance to Regulation 33 of these Regulations, for the respective years. Where actual equity employed is less than 30%, the actual equity and debt shall be considered;

rd is the Cost of Debt (or Interest and Finance Charges) as determined in Regulation 33 of these Regulations;

re is the pre-tax rate of Return on Equity as determined in Regulation 35 of these Regulations."

4.5 Return on Equity

4.5.1 Return on Equity essentially measures the rate of return that a company will earn on their equity investment. From the investor's point of view, every investment has a required rate of return broadly due to two reasons: the opportunity cost of foregone investments and the risk of business and its impact on the loan servicing. Since there are multiple investment opportunities, the investors choose the appropriate investment opportunity as per their risk-return profile. Regulated utilities are known for their ability to generate moderate but predictable returns regardless of market conditions.

4.5.2 In the regulated business returns are allowed to the Utilities for the investment made by them on its rate base. The National Tariff Policy and the Act lay downs the principle of tariff determination wherein the Utilities are allowed to recover cost of electricity in a reasonable manner and at the same time consumers interest is to be safeguarded. The relevant para from the National Tariff Policy, 2016 is reproduced as below:

"5.1. 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 SERCs for distribution with appropriate modification taking into view the risks involved. For uniform approach in this matter, it would be desirable to arrive at a consensus through the Forum of Regulators."

4.5.3 Further, the FOR Model Regulations for Multi-year Distribution tariff provides as under:

"27. Treatment of Return on equity

(a) Return on equity shall be computed on 30% of the capital base or actual equity, whichever is lower:

Provided that assets funded by consumer contribution, capital subsidies/grants and corresponding depreciation shall not form part of the capital base. Actual equity infused in the Distribution Licensee as per book value shall be considered as perpetual and shall be used for computation in this Regulation:

Provided, that accumulated depreciation, over and above debt repayment, shall be used to reduce the equity base for return on equity after debt repayment is over.

(b) The return on the equity invested in working capital shall be allowed from the date of start of commercial operation:

(c) Distribution Licensee shall be allowed [14%][3] post-tax return on equity."

4.5.4 To make sure that Return on Equity (RoE) is fair to both investors and consumers, the return allowed should be at par with the returns available from alternate investment opportunities with comparable risk. Different models, viz. Discounted Cash Flows (DCF), Risk Premium Model (RPM), Capital Asset Pricing Model (CAPM) etc. are available for the computation of the cost of equity/ RoE. However, the Commission has been majorly dependent on the CAPM model for arriving at RoE during previous tariff periods.

4.5.5 The GERC MYT Regulations, 2016 provides that,

> "*Return on equity shall be computed on the paid up equity capital determined in accordance with Regulation 33 on the assets put to use, for the Generating Company, Transmission Licensee, SLDC and Distribution Licensee as the case may be and shall be allowed at the rate of 14% for Generating Companies, including hydro generation stations above 25 MW, Transmission Licensee, SLDC and Distribution Licensee:*
>
> *Provided that for Generating Company, Transmission Licensee, SLDC and Distribution Licensee, Return on Equity shall be allowed on the amount of allowed equity capital for the assets put to use at the commencement of each financial year and on 50% of equity capital portion of the allowable capital cost for the investments put to use during the financial year:*
>
> *Provided further that for the purpose of truing up for the Generating Company, Transmission Licensee, SLDC and Distribution Licensee, return on equity shall be allowed based on documentary evidence provided for the assets put to use during the year*."

Issues Discussed in Discussion Paper

4.5.6 The GERC Discussion Paper for the draft GERC MYT Regulations, 2023 provides as under:

> "Section 61(d) of the Electricity Act, 2003, and Paragraph 5.11 (a) of the Tariff Policy 2016 have suggested to strike a balance between safeguarding of consumers' interest and recovery of the cost of electricity in a reasonable manner while laying down broad guiding principles for the determination of the rate of return.

4.5.7 Further, the Forum of Regulators, in its Report on "Analysis of Factors Impacting Retail Tariff and Measures to Address Them" has recommended as follows.

> *"In the entire value chain, transmission business has the lowest risk. The RoE for transmission companies should, therefore, be reviewed immediately. RoE for generation and transmission should be linked to the 10-year G Sec rate (average rate for last 5 years) plus risk premium subject to a cap as may be decided by Appropriate Commission. For a Discom, the RoE could be fixed*

based on the risk premium assessed by the State Commission. Income tax reimbursement should be limited to the RoE component only."

4.5.8 It is also observed that the Forum of Regulators (FOR) has recommended differential RoE for Generation and Transmission Businesses with a reduction in RoE for Transmission Business.

4.5.9 For computation of expected cost of Equity, capital asset pricing model (CAPM) is the most widely used method. According to this method, the expected cost equity can be calculated as:

Ra = Rf + [β x (Rm – Rf)]

Where:

Ra = Expected rate of return (Cost of Equity)

Rf = Risk-free rate

β = Beta of the security

Rm = Expected return on market

4.5.10 Further, considering the longer periods of data while computing RoE using the CAPM, provides the reliable results as it averages out the period of higher and lower returns and economic uncertainties. Therefore, data for 10 year period for risk free rate, beta and expected return on market may be considered.

4.5.11 The second approach would be to link the expected rate of return with market interest rates such as G-SEC rates/RBI Repo Rate plus certain spread, which will reflect the appropriate risk levels and be lucrative to the investor for enabling future investments."

Suggestion/Comment from Stakeholders:

1) **Adani Power Limited** suggested that:

   a. The rate prevailing in the previous MYT regulations i.e. 14% should not be reduced for Transmission utilities as it would hamper the potential investment in the sector.

   b. Further, this segment is already facing a lot of problems such as insolvency and reducing the rate or linking the rate to G-Sec Rate/MCLR/RBI Base Rate will further aggravate it.

   c. Additional RoE should be allowed for incentivizing investments in the sector and that the RoE should be fixed for the entire life of the project.

   d. The base rate of RoE should not be reduced and any incentive should be over and above the base rate.

2) **MPSEZ Utilities Limited** has requested to:

   a. Maintain the *RoE at minimum 15.5%* and not reduce it further.

   b. Not take the approach of linking RoE with the G-sec rate/ MCLR/ RBI Base Rate to provide certainty to the investors.

   c. Keep rate for incentivization over and above the base rate by not reducing the same.

3) **GSECL** suggested that:

   a. Linking RoE with G-Sec rate/ MCLR/ RBI Base Rate plus certain spread will not reflect actual market risk associated with the investment.

   b. CAPM model should be used for computing the cost of equity to give realistic view.

   c. Reducing in rate of RoE will be detrimental for the operation of plant as the plant will start making losses and gradually it will not be feasible to maintain plant performance and the RoE should be kept at 14%.

4) **Prayas Energy Group** suggested that:

   a. The approach of linking RoE rates with G-Sec rate/ MCLR/ RBI Base Rate with decent risk premium can be considered since Section 62 projects inherently have very low risk.

   b. Since, section 62 projects have very low risk, the risk premium calculated from market returns is not appropriate for such projects and cap should be decided by the commission.

   c. In addition to delays in filing of petition, penalty on ROE could also be implemented for delays in completion of projects, given the impact of such delays on the sector costs and power purchase planning, and to ensure the project proponent is held accountable.

5) **GUVNL** submitted that:

   a. Distribution Licensee have to handle large consumer base, comparatively large distribution network.

   b. Further, certain performance parameters such as distribution losses, bad debt, variation in number / mix of consumers due to migration of consumer to other licensee etc are considered as controllable parameters severely impacting the effective rate for distribution licensee due to variation in performance as compared to target.

c. Due to challenges faced by Distribution Licensee, the proposition of linking the return for distribution incense with expected market rate of return / market interest rate will lead to further uncertainty in the return available to the distribution licensee. *The licensee has requested to keep the RoE at least 14%.*

d. With regard to splitting up of equity, they submitted that RoE base rate should be retained at 14% and rate over and above base RoE i.e. 1.5% should be linked with achievement of performance targets.

6) **GETCO** has submitted that:

a. Reducing the RoE for Transmission business is detrimental to their growth as there is precarious scenario already prevailing since 2018-19 and they are facing adversities like RoW, land acquisition, forest clearances, other statutory clearances, time, and cost overrun along with long gestational period to develop the transmission network.

b. Contractors of the GETCO are facing Supply chain disruptions, labour migrations, funding problems etc. and going into CIRP process in between.

c. Accordingly, since most SERCs has approved RoE @ 15.50% hence, *they propose to submit same rate of return for transmission business.*

7) **TPL** submitted that:

a. Base RoE for Generation and Transmission shall be15.50% in line with CERC Regulations. Further, considering risk involved in the distribution business, Base RoE should be (i) 16.00 % for Supply Business and (ii) 16.50% for Wire Business.

b. RoE approach should be followed and alignment with the Tariff Regulations should be there by following GFA concept.

4.5.12 Additional ROE to be allowed for incentivizing the utility over and above base ROE of 15.5 % for Generation and Transmission and ROE for Distribution of 16% / 16.5% by factoring risk premium.

Commission’s View:

4.5.13 The Capital Asset Pricing Model (CAPM) is typically used to determine the cost of equity. It is recognized that this model will not give the exact rate of return on equity, as it assumes data which is taken as input. However, the CAPM gives an approximate rate of return on equity, which can be used to take an informed decision on rate of return on equity.

4.5.14 The CAPM describes the relationship between the expected return and risk of investing in a security. It shows that the expected return on a security is equal to the risk-free return plus a risk premium, which is based on the beta of that security.

4.5.15 CAPM can be summarized according to the following formula:

Required (or expected) Return = Risk Free Rate + (Market Return – Risk Free Rate) x Beta

4.5.16 For estimating rate of RoE the following steps needs to be followed:

Step 1: Calculate historical market returns for the past 10 / 15 / 20 years using BSE Sensex data to determine Rm

Step 2: Calculate risk free rate for similar period of 10 / 15 / 20 years using 10-year Govt. Bond yields

Step 3: Estimate the Beta for power sector utilities using data of listed Indian companies, as demonstrated below

a. Calculate equity beta for major listed firms and determine average of equity betas

b. Calculate each firm's financial leverage and determine the average of financial leverage.

c. Un-Lever the average equity beta using average financial leverage to get average un-levered beta

d. Re-lever the average un-levered beta using normative financial leverage.

Unlevered Beta is computed as follows:

$$\text{Unlevered Beta} = \frac{\text{Levered Beta or Equity Beta}}{(1 + ((1 - \text{Tax Rate}) \times (\text{Debt/Equity})))}$$

4.5.17 We have analyzed the data for various listed entities and have considered a period of 13 years for each of the components of CAPM i.e. risk free rate, equity beta and market risk premium, as most of the listed companies shortlisted have become operational post 2010. Further, the intention is to exclude the period of uncertainty due to 2008 financial crisis.

4.5.18 The market return has been estimated based on historical data of returns of BSE Sensex. The market return for a period from 2010-23 was 11.356%.

(a) Risk free rate is estimated using yield of 10-year government bond. The Risk free rate (Rf) based on 10-year Indian government bond yield for 2010-23 works out to be 7.427%.

4.5.19 The table below provides the details of computation of un-levered beta:

Table 1: Details of computation of un-levered beta

Firm	Equity / Levered Beta	D/E	Tax Rate	Un-levered Beta
Power Grid	0.703	2.291	25%	0.259
Tata Power	1.054	1.700	25%	0.463
Adani Power	1.228	2.560	25%	0.421
Torrent Power	0.769	0.950	25%	0.449
Reliance Power	1.017	0.380	25%	0.792
GIPCL	0.805	0.150	25%	0.724
Overall Average	**0.930**	**1.339**	**25%**	**0.518**

The tax rate is assumed to be 25%

Re-levering the Beta

The average un-levered beta for key listed companies in the power sector is levered considering the normative debt – equity ratio of a project i.e. **70:30.** The expected beta calculated is as follows:

Levered Beta = Unlevered Beta (1+ (Debt-Equity Ratio) *(1-Tax Rate))

*Levered Beta = 0.518 (1+ (70/30) * (1-25%))*

= ***1.424***

Thus, the beta considered for the calculation of expected return is estimated at 1.424.

Calculating the expected returns:

Expected rate of return = *Rf + [b x (Rm – Rf)]*

= 7.427% + [1.424 x (11.356 - 7.427)]

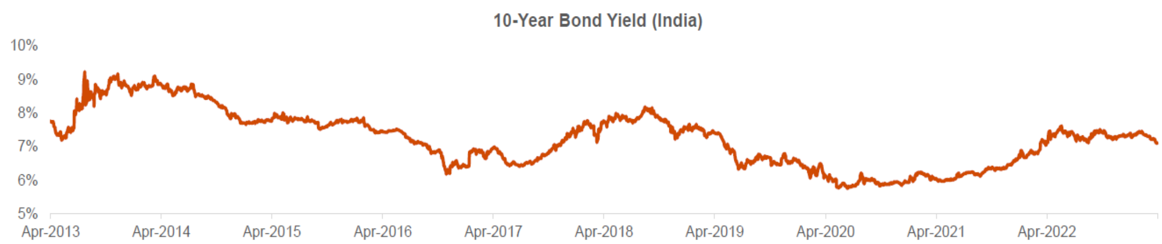
= ***13.003%***

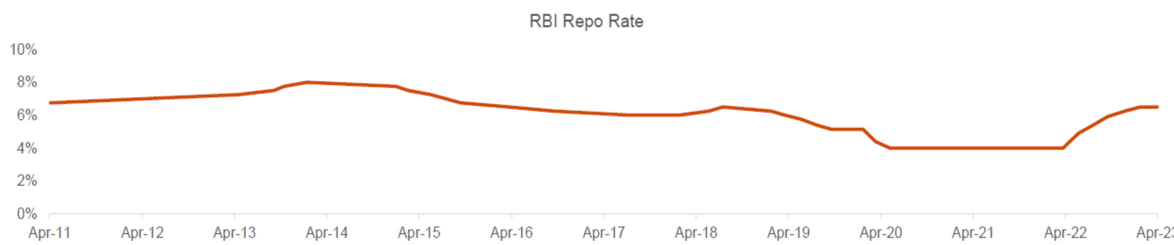
*Thus**, it can be observed that using the CAPM model, the expected return works out to be 13.003% which is less than the existing rate of return i.e., 14%.***

4.5.20 Considering that this is a fourth MYT Regulations to be implemented for FY 2024-25 to FY 2028-29, whereby the utilities has been acquainted with the MYT Regulations, it is time for switchover from the Cost-Plus approach to Performance based approach in relation to Return on Equity in a gradual way. Therefore, the RoE is proposed to be bifurcated into Base RoE of 13% as discovered above and Performance Linked RoE for Generating Companies, Transmission Licensee and SLDC as per respective factors as discussed in the ensuing paragraphs.

4.5.21 Further, the base RoE of 13% has been considered for the transmission and wires business considering a lower gestation period and lower business risk. However, the Commission proposes to consider the base RoE of 13.5% and 14% for thermal generating station and hydro generating station considering the higher gestation period. Further, retail supply being a consumer centric business faces a higher degree of business risk due to unavailability of payment security mechanism unlike for transmission and generation businesses, therefore, a base RoE of 14% has been considered for the retail supply business.

4.5.22 The second approach which was discussed in the discussion paper was to link the expected rate of return with market interest rates such as G-Sec rates/ RBI Base Rate plus certain spread which will reflect the appropriate risk levels and will directly link the returns to the alternative investment opportunities that are available in the market. The figures below provide the variation in 10-year Government Bond yield and RBI Repo rate over the last 10 years:





4.5.23 Based on the discussion since we are suggesting that the maximum rate of return on equity for companies to be 13%. Therefore, to link the RoE with the existing benchmark norms and to assure the maximum base rate of 13% based on the historical data, the risk spread in the range of 550 basis points to 750 basis points was required to be allowed. The wider range of spread over the benchmark rates will bring the regulatory uncertainty especially considering the long horizon of the investment in the power sector. Therefore, the Commission is inclined to consider the first approach where a maximum base rate of 13% has been considered as RoE.

<u>Splitting of Rate of Return on Equity</u>

4.5.24 The current regulations provide for one composite rate of return on equity (RoE) to be 14%. However, few SERCs (State Electricity Regulatory Commission) follow the approach of splitting up of RoE into two components i.e., a fixed component (being base rate) and another variable component which is linked to the improved operational performance of the utilities. The thought behind splitting the RoE into two components is to incentivize better performing utilities based on performance parameters, subject to third-party verification by Commission.

4.5.25 We suggest that the below mentioned differential rates for different categories of utilities -

1. ***Transmission, SLDC & Distribution (Wires Business) Utilities:***

We are suggesting a base rate of 13% for the transmission, SLDC and Distribution (wires business) utilities, given the logic that in the CAPM model built we have taken into consideration the major companies in transmission and distribution sector. Further, the transmission utilities face the lowest risk in the entire value chain as given by the Forum of Regulators (FOR), in its Report on *“Analysis of Factors Impacting Retail Tariff and Measures to Address Them”* with regard to RoE. Suggested parameters for incentivizing shall be:

a. For Transmission utilities it will be subjected to Transmission Availability and reduction in transmission loss beyond the limit provided by Commission.

b. For SLDC it will be subjected to target availability of SCADA, website and capitalization of investment works in a financial year if exceeding the limit.

c. For Distribution wire utilities it will be subjected to target availability of wires, overachieving of distribution losses & over-achieving of smart metering implementation targets.

2. ***Generation Utilities:***

For Generation utilities we propose an additional rate of 0.5% over the rate of 13%, hence, the base expected RoE comes out to be 13.5%. The suggested parameters for incentivizing generation utilities are the increase in ramp rate and the mean time between failure.

3. ***Hydro Generation Utilities:***

For Hydro Generation utilities we propose an additional rate of 1% over the rate of 13%, hence the base expected RoE comes out to be 14%. The hydro power projects have long gestation period they involve huge degree of risks viz Geological surprises, Social, Political, natural Calamities & other risks. Considering all the risks faced by hydro generation utilities, it is essential to incentivize them in addition to the base rate. Furthermore, this rate is at par with the existing RoE.

4. ***Retail Supply Utilities:***

For retail supply utilities, we propose an additional rate of 1% over the rate of 13%, hence the base expected RoE comes out to be 14%. The suggested parameters for incentivizing retail supply utilities are overachievement of collection efficiency targets, Percentage of assessed bills as a percentage of total bills issued in a year, Implementation of ToD based tariff for Residential Consumer categories.

Final Draft Regulations

4.5.26 In view of the discussion in the foregoing paragraphs, the Commission proposes the following provision for Rate of Return on Equity in the draft Regulations:

"35.1 Maximum Return on Equity that shall be allowed on the equity capital determined in accordance with Regulation 32 of these Regulations for the assets put to use, up to the rate per annum in Indian Rupee terms is as mentioned below:

Generating Station – Thermal and Gas based	-	*13.50 %*
Generating Station – Hydro	-	*14.00 %*
Transmission Licensee	-	*13.00 %*
SLDC	-	*13.00 %*
Distribution Licensee		
(i) Wire Business	-	*13.00 %*
(ii) Retail Supply Business	-	*14.00 %*

Provided that Return on Equity shall be allowed in two parts viz. Base Return on Equity, and Additional Return on Equity linked to actual performance:

Provided further that Additional Return on Equity shall be trued-up for respective year based on actual performance substantiated by documentary evidence, after prudence check by the Commission.

Provided further that the Commission may conduct a third-party verification of the performance parameters based on which the additional Return on Equity is being allowed.

35.2 Base Return on Equity shall be allowed on the equity capital determined in accordance with Regulation 32 of these Regulations for the assets put to use, in Indian Rupee terms as follows:

(a) Thermal and Gas based Generating Stations – 12.00% per annum;

(b) Hydro Generating Stations – 14.00% per annum (without any break-up between base RoE and incremental RoE);

(c) Transmission Licensee, SLDC and Wire Business of Distribution Licensee – 11.50% per annum; and

(d) Retail Supply Business of Distribution Licensee – 12.50%:

Provided that in case Generating Company or Transmission Licensee or SLDC or Distribution Licensee claims Return on Equity at a rate lower than the normative rate specified above for any particular year, then such claim for lower Return on Equity shall be unconditional:

Provided further that such claim for lower Return on Equity shall be allowed subject to the condition that the reduction in Return on Equity shall be foregone permanently for that year and shall not be allowed to be recouped at the time of Mid-Term Review or true-up as applicable.

35.3 The Base Return on Equity shall be computed in the following manner:

(a) Return at the allowable rate as per this Regulation, applied on the amount of equity capital at the commencement of the Year; plus

(b) Return at the allowable rate as per this Regulation, applied on 50 per cent of the equity capital portion of the allowable capital cost, for the investments put to use in Generation Business or Transmission Business or Distribution Business or SLDC, for such year.

35.4 In case of a new project, the rate of Return on Equity shall be reduced by 1.00% for such period as may be decided by the Commission, if generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the SLDC.

35.5 In case of existing generating station, as and when any of the requirements under Regulation 35.4 of these Regulations are found lacking based on the report submitted by the SLDC, rate of Return on Equity shall be reduced by 1.00% per year at the time of true-up, for the period for which the deficiency continues.

35.6 In case of a thermal generating unit, with effect from April 01, 2024, the additional rate of Return on Equity shall be trued-up subject to the following:

(a) an additional rate of Return on Equity of 0.125% shall be allowed for every incremental ramp rate of 1% per minute achieved over and above the ramp rate of 1% per minute, subject to ceiling of additional rate of Return on Equity of 0.50%, for the year in which such ramp rate is achieved.

Provided that additional rate of Return on Equity shall be allowed on pro-rata basis for incremental ramp rate of more than 1% per minute.

(b) an additional rate of Return on Equity shall be allowed as per the following schedule:

(i) 0.50% for Unit that achieves Mean Time Between Failure (MTBF) of at least 45 days;

(ii) 0.75% for Unit that achieves Mean Time Between Failure (MTBF) of at least 90 days;

(iii) 1.00% for Unit that achieves Mean Time Between Failure (MTBF) of at least 120 days:

Provided that the Mean Time Between Failure (MTBF) shall be computed as provided in Annexure IV to these Regulations:

Provided further that the equity base for the respective unit shall be considered in proportion to the installed capacity of the generation station, in case the tariff is determined for the generation station as a whole.

35.7 In case of Transmission Licensee, with effect from April 01, 2024, the additional rate of Return on Equity shall be trued-up subject to the following:

(a) an additional rate of Return on Equity of 0.25% shall be allowed on Transmission Availability for every 0.25% over-achievement from 98.50% for AC System and 95.00% for HVDC bi-pole links and HVDC back-to-back stations, up to Transmission Availability of 99.50% for AC System and 96.00% for HVDC bi-pole links and HVDC back-to-back stations,, subject to ceiling of additional rate of Return on Equity of 1.00%;

(b) an additional rate of Return on Equity of 0.50% shall be allowed to the Transmission Licensee for reducing transmission loss levels beyond the lower limit of 0.10% of transmission loss trajectory provided by the Commission from time to time.

35.8 In case of SLDC, with effect from April 01, 2024, an additional rate of Return on Equity shall be trued-up, subject to the following:

(a) Target Availability of SCADA System will be 98.00% and for every 0.50% over-achievement in Availability, rate of return shall be increased by 0.25%, subject to ceiling of additional rate of Return on Equity of 0.50%;

(b) Target Availability of Website Availability will be 98.00% and for every 0.50% overachievement in Availability, rate of return shall be increased by 0.25%, subject to ceiling of additional rate of Return on Equity of 0.50%;

(c) Additional rate of Return on Equity of 0.50% shall be allowed, if the total value of capital investment works capitalized in a financial year exceeds 80% of the approved capitalization of approved capital investment works.

35.9 From the beginning of third year of the Control Period, in case of Transmission Licensee- Gujarat Electricity Transmission Corporation Limited (GETCO) and SLDC, the additional rate of Return on Equity as mentioned in Regulation 35.7 and Regulation 35.8 of these Regulations, shall only be allowed, in case the SLDC is constituted as a separate and independent legal entity from GETCO in accordance with the provisions of Section 31(2) of the Act.

35.10 In case of Distribution Wires Business, with effect from April 01, 2024, an additional rate of Return on Equity shall be trued-up, subject to the following :

(a) Target Wires Availability for recovery of base rate of return on equity shall be 96.00% for state government owned Distribution Licensees and 97.00% for other Distribution Licensees;

(b) For every 0.50% over-achievement in Wires Availability, rate of return shall be increased by 0.25%, subject to ceiling of additional rate of Return on Equity of 0.50%;

(c) Wires Availability shall be computed in accordance with the following formula:

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

Provided that the System Average Interruption Duration Index (SAIDI) shall be calculated in accordance with the definition specified in Gujarat Electricity Regulatory Commission (Standards of Performance of Distribution Licensees, Period for Giving Supply and Determination of Compensation) Regulations, 2005, as amended from time to time;

(d) an additional rate of Return on Equity shall be allowed up to ceiling limit of 0.50% to state government owned Distribution Licensees for overachieving distribution loss levels by at least 0.10% or more as per the distribution loss

level trajectory provided by the Commission in the MYT Order for the Control Period;

(e) an additional rate of Return on Equity shall be allowed up to ceiling limit of 0.50% to state government owned Distribution Licensees for overachieving smart metering implementation target or any other performance parameter as per the trajectory provided by the Commission in the MYT Order for the Control Period:

Provided that the mechanism for additional rate of Return on Equity, for the Wire Businesses of the Distribution Licensees other than state government owned Distribution Licensees, in lieu of clauses (d) and (e) above, shall be provided by the Commission in their respective MYT Orders.

35.11 In case of Retail Supply Business, with effect from April 01, 2024, an additional rate of Return on Equity on achievement of target performance parameters including overall collection efficiency, percentage of assessed bills over total bills or any other performance parameter shall be trued-up as per the trajectory provided by the Commission in the respective MYT Orders.

35.12 From the third year of the Control Period, in case of Distribution Licensees, the additional rate of Return on Equity as mentioned in Regulations 35.10 and 35.11 of these Regulations, shall only be allowed to Distribution Wire Business and Retail Supply Business, if separate books of accounts for the Distribution Wire Business and Retail Supply Business are maintained by the Distribution Licensee, and certified copies of such accounts from the Statutory Auditor are submitted along with the truing-up petitions for the respective financial years:

Provided that the guidelines specified by the Commission as per Annexure V to these Regulations to be followed.

35.13 For the purpose of truing up for Generating Company, Transmission Licensee, SLDC and Distribution Licensee, Return on Equity shall be allowed on the amount of allowed equity capital for the assets put to use at the commencement of each financial year and on 50% of equity capital portion of the allowable capital cost for the investments put to use during the financial year.

35.14 Assets funded by consumer contributions, capital subsidies/Govt. grants shall not form part of the capital base for the purpose of calculation of Return on Equity.

35.15 Premium if any, raised by Generating Company or Transmission Licensee or SLDC or Distribution Licensee while issuing share capital and investment of *internal resources created out of free reserve, if any, shall also be reckoned as paid up capital for the purpose of computing return on equity, provided such premium amount and internal resources are actually utilised for meeting capital expenditure, and are within the ceiling of 30% of capital cost approved by the Commission."*

4.6 Interest on Working Capital

4.6.1 Cost Recovery of the Emission Control System will be through generation tariff only. Hence to accommodate it, the Commission has introduced regulation 38.1.1 for Coal or Lignite based Thermal Generating Station with Emission Control System in line with the CERC Tariff Regulations for 2019 – 24, same has been produced below:

"38.1.2 In case of Emission Control System of coal or lignite based thermal generating stations, working capital shall be allowed to cover:

(i) Cost of limestone or reagent towards stock for 20 days for generation corresponding to the target availability;

(ii) Normative Operation and maintenance expenses in respect of emission control system for one month;

(iii) Maintenance spares at one per cent of the opening Gross Fixed Assets in respect of emission control system."

4.7 Income Tax

4.7.1 The Commission currently follows the approach of allowing the normative tax as per actuals subject to prudence check.

4.7.2 While following the approach of allowing income tax as per actuals, there might be a possibility of burdening the consumers with the income tax pertaining to other income/business, earning on account of efficiency target overachievement and other incentive provided by central / state government in the infrastructure. In order to segregate the income tax pertaining to core business, the utility have to maintain the expenditure pertaining to different stream separately in their books of accounts or has to be certified by a statutory auditor.

4.7.3 However, following the approach of grossing up of RoE based on effective tax rate (as per ITR), it ensures that tax is being allowed only on RoE part and are able to pass on the benefits and concessions available in income tax to the beneficiaries. However, the tax rate at which it should grossed up needs to be deliberated. A guidance can be taken from CERC Approach Paper for 2024 Tariff Regulations in this regard, which stipulates:

"4.17……………

In view of the above discussion and recent amendments to the Income tax regime, a domestic company shall fall under one of the following brackets, and the maximum tax amount that shall be payable is limited by the tax rates notified for the relevant category. Therefore, Base Rate of RoE may be grossed up as follows:

1. At MAT rate (If not opted for Section 115 BAA)

2. At effective tax rate (if not opted for Section 115BAA) subject to ceiling of Corporate Tax Rate; or

3. At reduced tax rate under Section 115BAA of the Income Tax Act or any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act.

….."

Issues discussed in Discussion Paper:

4.7.4 Based on the above, the following options were proposed in the discussion paper:

"Accordingly, it proposed to introduce a capping on the pass through of tax only upto to the effective tax rate (to be computed based on tax paid as a percentage of assessed profits as per Assessment Order issued by the Income Tax Authority) on the average/opening equity balance allowed by the Commission for the financial year as recommended above.

Further, one of the possible approaches could be to allow return on equity sans any income tax as pass-through to the Utilities."

Suggestion/Comment from Stakeholders:

1) Adani Power Limited suggested that the income tax shall be allowed on normative basis by grossing up the base rate of return on equity irrespective of actual tax paid by the company due to loss / profit in the other business. Further, they submitted that tax on income clause contradicts the clause 2.1.4 regarding pre vs post tax RoE and needs to be revisited.

2) MPSEZ Utilities Limited suggested that the income tax shall be allowed on normative basis by grossing up the base rate of return on equity irrespective of actual tax paid by the company due to loss / profit in the other business. Further, the existing methodology of Income Tax should be retained and should be allowed on actual tax paid by the company due to loss / profit in the other business with no capping.

3) GSECL suggested that the actual income tax paid to Government, i.e., tax recovered from GUVNL is not more than the actual tax paid to Government. Thus, recovery of tax is being allowed based on 'no profit no loss' basis as a sort of reimbursement. Therefore, existing approach of allowing return may be continued. They further suggested that for tax on income existing regulation should be continued.

4) GUVNL suggested that pre-tax RoE approach in effect allows tax on the applicable income tax which gives undue additional benefit to entities in the name of income tax. The correct approach could be to allow post-tax return (i.e., income tax worked out on the approved RoE by applying applicable tax rates)'. The income tax liability worked out by applying appropriate income tax rates on approved RoE or income tax actually paid, whichever is lower shall be allowed towards Tax on income.

5) TPL submitted that **e**xisting mechanism of allowing recovery of actual income tax paid on prorate basis of PBT to be continued.

Commission's View:

4.7.5 The Commission has noted the submissions made by the stakeholders.

4.7.6 The Commission has proposed the return on equity based on the expected returns computed through Capital Asset Pricing Model (CAPM). However, CAPM is usually built with a certain set of assumptions i.e.:

a) All investors are risk-averse by nature.
b) Investors have the same time period to evaluate information.
c) There is unlimited capital to borrow at the risk-free rate of return.
d) Investments can be divided into unlimited pieces and sizes.
e) There are no taxes, inflation, or transaction costs.
f) Risk and return are linearly related

4.7.7 Therefore, the RoE for different entities have been proposed considering that there are no tax adjustment in the expected return and therefore, the same shall be allowed separately.

4.7.8 The Commission is inclined to continue with the existing approach of grossing up the RoE with Income Tax based on the effective tax rate computed as the actual tax paid as a percentage of assessed profits as per Assessment Order issued by the Income Tax Authority.

4.7.9 Further, tax shall be allowed only in cases where the company has actually paid taxes as under no circumstances tax can be allowed to be recovered if the company has not paid any tax for the year under consideration.

4.7.10 The Commission has not considered the second approach i.e. to allow return on equity sans any income tax as pass-through to the Utilities, as this approach will require an adjustment in the rate of RoE to offset the normative tax as decided by the Commission, which may lead to abnormal profit to the entities who are paying low or Nil income tax and losses to the entities who are performing well and paying taxes.

Final Draft Regulations

4.7.11 In view of the discussion in the foregoing paragraphs, the Commission proposes the following provision for Income Tax in the draft Regulations:

"39 Income Tax

39.1 Income tax for Generating Company or Transmission Licensee or SLDC or Distribution Licensee for the regulated business shall be allowed on Return on Equity, including Additional Return on Equity through the tariff charged to the Beneficiary/ies, subject to the conditions stipulated in Regulation 35 and 36 of these Regulations:

Provided that no Income Tax shall be considered on the amount of efficiency gains and incentive approved by the Commission, irrespective of whether or not the amount of such efficiency gains and incentive are billed separately:

Provided further that no Income Tax shall be considered on the amount of income from Delayed Payment Charges or Interest on Delayed Payment or Income from Other Business, as well as on the income from any source that has not been considered for computing the Aggregate Revenue Requirement:

Provided also that the Income Tax shall be computed for the Generating Company as a whole, and not Unit-wise/Station-wise:

Provided also that the deferred tax liability attributable to the regulated business, only before March 31, 2024 shall be allowed by the Commission, whenever they get materialised, after prudence check.

39.2 The rate of Return on Equity, shall be equal to the base rate of Return on Equity and additional rate of Return on Equity as allowed by the Commission under Regulation 35 of these Regulations, which shall be grossed up with the effective tax rate of respective financial year.

Provided that the rate of return on equity shall be grossed up with the effective tax rate on the basis of actual tax paid on the Book profit, in respect of financial year in line with the provisions of the relevant Finance Acts by the concerned the Generating Company or Transmission Licensee or SLDC or Distribution licensee, *as the case may be.*

39.3 *Rate of pre-tax Return on Equity shall be rounded off to three decimal places and shall be computed as per the formula given below:*

Rate of pre-tax return on equity = Rate of Return on Equity / (1-t),

Where "t" is the effective tax rate is calculated on the basis of actual income tax paid latest available Assessment Order issued by income tax authority under provisions of Income tax Act 1961, as amended from time to time.

Provided that in case of Generating Company or Transmission Licensee or SLDC or Distribution licensee has engaged in any other regulated or unregulated Business or Other Business, the actual tax paid on income from any other regulated or unregulated Business or Other Business shall be excluded in proportion to the income from the said business for the calculation of effective tax rate:

Provided further that effective tax rate shall be estimated for future year based on latest available Assessment Order issued by income tax authority under provisions of Income tax Act 1961, as amended from time to time, subject to prudence check.

39.4 *In case of Generating Company or Transmission Licensee or SLDC or Distribution licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess:*

Illustration:-

(a) *In case of a Generating Company or Licensee or SLDC paying Minimum Alternate Tax (MAT) at rate of 17.472% including surcharge and cess:*
Rate of return on equity = 14/(1-0.17472) = 16.964%

(b) *In case of Generating Company or Licensee or SLDC paying normal corporate tax including surcharge and cess:*
   (i) *Net Income of Company before deduction under section 80 of income tax act 1961, as a whole for FY 2024-25 is Rs. 500 Crore;*
   (ii) *Income Tax for the year on above is Rs. 110 Crore;*
   (iii) *Effective Tax Rate for the FY 2024-25 = Rs 110 Crore/Rs 500 Crore = 22%;*
   (iv) *Rate of return on equity = 14/ (1-0.22) = 17.949%.*

(c) In case of Generating Company or Licensee or SLDC has incurred loss resulting in no Income tax, the effective tax rate will be zero and only Rate of Return on Equity as approved by the Commission will allowed to be claimed in ARR:

(i) Net Loss of Company before deduction under section 80 of income tax act 1961, as a whole for FY 2024-25 is Rs. 150 Crore;

(ii) Income Tax for the year on above will be ZERO.

(iii) Effective Tax Rate for the FY 2024-25 = Rs 0 Crore/ Rs. (150 Crore) = 0%;

(iv) Rate of return on equity = 14/ (1-0.00) = 14%.

Provided that if the effective tax rate is lower than the Minimum Alternate Tax or Corporate Tax Rate, then the same will be considered for grossing up the rate of return on equity.

Provided that in case the actual income tax paid including Cess and Surcharge, is lower than the difference between Pre-Tax Return on Equity and Post-Tax Return on Equity (Base Rate of Return on Equity Plus Additional Rate of Return on Equity), then the actual income tax paid will be considered as a pass through.

39.5 Under-recovery or over-recovery of any amount from the beneficiaries or the consumers on account of such tax having been passed on to them shall be adjusted every year on the basis of income-tax assessment under the Income-Tax Act, 1961, as certified by the statutory auditors. Generating Company, or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, may include this variation in its truing up petition.

39.6 Penalty, if any, arising on account of delay in deposit or short deposit of tax amount shall not be claimed by the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be.”

4.8 Interest and finance charges

4.8.1 As per existing provisions of the GERC MYT Regulations, the interest rate for computation of interest and finance charges is calculated based on the weighted average interest rate of actual loan portfolio of the utility. The interest rate thus arrived at is applied on the normative outstanding loan to compute the annual interest and finance charges of the utility. Repayment of loan being considered equal to the depreciation.

4.8.2 The Regulation 38 in the existing GERC MYT Regulations, 2016 provides that, "*38.1 The loans arrived at in the manner indicated in Regulation 33 on the assets put to use, shall be considered as gross normative loan for calculation of interest on loan:*

Provided that interest and finance charges on capital works in progress shall be excluded:

Provided further that in case of de-capitalisation or retirement or replacement of assets, the loan capital approved as mentioned above, shall be reduced to the extent of outstanding loan component of the original cost of the de-capitalised or retired or replaced assets, based on documentary evidence.

38.2 The normative loan outstanding as on April 1, 2016, shall be worked out by deducting the cumulative repayment as admitted by the Commission up to March 31, 2016, from the gross normative loan.

38.3 The repayment for the year during the Control Period from FY 2016-17to FY 2020-21shall be deemed to be equal to the depreciation allowed for that year.

38.4 Notwithstanding any moratorium period availed by the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed.

38.5 The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee:

Provided that at the time of truing up, the weighted average rate of interest calculated on the basis of the actual loan portfolio during the year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee shall be considered as the rate of interest:

Provided further that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest for the actual loan shall be considered:

Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, then the weighted average rate of interest of the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission shall be considered:

Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, and the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission also does not have actual loan, then the weighted average rate of interest of the

Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole shall be considered:

Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole does not have actual loan, then the Bank Rate plus 200 basis points shall be considered as the rate of interest for the purpose of allowing the interest on the normative loan.

38.6 The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest:

Provided that at the time of truing up, the normative average loan of the year shall be considered on the basis of the actual asset capitalisation approved by the Commission for the year.

38.7 The above interest computation shall exclude interest on loan amount, normative or otherwise, to the extent of capital cost funded by Consumer Contribution, Grants or Deposit Works carried out by Transmission Licensee or SLDC or Distribution Licensee or Generating Company, as the case may be.

38.8 The Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, in the ratio of 2:1.

38.9 Interest shall be allowed on the amount held as security deposit held in cash from Transmission System Users, Distribution System Users and Retail consumers at the Bank Rate as on 1st April of the financial year in which the Petition is filed."

Issues discussed in Discussion Paper:

4.8.3 As stated in the discussion paper, the treatment of normative loan of majority of the ERCs are more or less similar. It is proposed to continue with the existing approach of considering the addition in line with the normative debt to equity ratio and repayment linked to allowed depreciation for the year.

Suggestion/Comment from Stakeholders:

1. Adani Power Limited suggested that:

- Interest on loan is not a controllable parameter hence should not be capped.
- Capping of interest would result in under recovery of tariff and may worsen their financial situation.

2. MPSEZ Utilities Limited suggested that:

- Interest on loan is not a controllable parameter hence should not be capped.
- Capping of interest would result in under recovery of tariff and may worsen their financial situation.
- Allowing interest on loan as per CERCs approach in case of absence of actual loan by a utility for the regulated business.
- Weighted average rate of interest should be considered for the whole business including parent company.

3. GUVNL suggested that:

- It would be appropriate to allow interest on normative loan and the decision to obtain funds though debt financing or internal sources may be left with utilities.
- They requested the Commission to provide for spread over the benchmark rate of interest for allowing interest on loan amount.

4. TPL submitted that:

- Cap on interest is not required given interest rate is an uncontrollable factor.
- Since DISCOMs have a very little bargaining power due to unrecovered regulatory assets hence it would further result in increase in interest rates.
- Capping is against the principle of Electricity Act/ Tariff policy to ensure recovery of all legitimate cost of supply.

Commission's View:

4.8.4 The interest on loan is computed as WAROI calculated on the basis of the actual loan portfolio during the year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee. Since different licensees have different business risk profile and the above methodology sometime allows the inefficiencies of licensees with high risk profile to be passed on to the consumers. Considering that this is a fourth MYT Regulations to be implemented for FY 2024-25 to FY 2028-29, whereby the utilities has been acquainted with the MYT Regulations, it is time for switchover from the Cost-Plus approach to Performance based approach in relation to Interest on Loan in a gradual way.

4.8.5 Therefore, it is proposed to continue with the approach of allowing interest on loan as WAROI calculated based on the actual loan portfolio during the year within a band while restricting the interest to the upper band limit. If any utility is able to procure the loan at the interest rates lower than the prescribed lower limit, then the utility will be able to earn on account of efficient financing subject to gain sharing regulations. Further, the utilities shall make all the efforts for refinancing, only in the event of generation of net savings, and such savings shall be subjected to the gain sharing regulations. It is pertinent to note that refinancing shall be allowed subject to the condition that resultant WAROI will falls below the upper limit of the band.

4.8.6 The band has been decided considering the historical data for actual rate of interest of all the utilities and mapping the same to the widely published benchmark norms. It will present the opportunity to the utilities faring worse among the peers to reduce their interest rate and bring it within the prescribed limit.

4.8.7 The table below provides the weighted average rate of interest for various distribution utilities in Gujarat:

Table 2: Weighted Average Rate of Interest for Various Distribution Utilities

FY	PGVCL	MGVCL	DGVCL	UGVCL	TPL-DA	TPL-DS
2011-12	9.39%	9.74%	9.23%	8.10%		
2012-13	9.39%	10.48%	10.23%	9.76%		
2013-14	9.02%	9.56%	10.24%	9.19%		
2014-15	9.53%	8.51%	10.27%	9.28%		
2015-16	8.09%	9.46%	13.16%	7.27%		
2016-17	9.26%	8.37%	10.49%	9.93%	11.21%	11.12%
2017-18	9.69%	9.26%	11.75%	9.96%	8.54%	8.54%
2018-19	9.07%	6.13%	11.01%	9.69%	8.69%	8.66%
2019-20	9.71%	6.15%	10.88%	8.30%	8.94%	9.07%
2020-21	10.94%	6.30%	10.76%	8.20%	7.84%	7.94%
2021-22		11.88%	10.69%		7.27%	7.58%
2022-23	14.72%	12.29%		14.60%		

From the table above, it can be observed that the interest rates varies widely across DISCOMs on year-on-year basis.

4.8.8 We have analyzed the interest on loan for various entities under GERC with that of 1 - year SBI MCLR rate considering most of the debt available in the market are linked with one-year SBI MCLR. Given the varied rates of 1-year SBI MCLR during the year, we have considered the average of rate prevailing during the respective Financial Year.

Table 3: Weighted Average Interest Rate with 1 - Year SBI MCLR

FY	PGVCL	1-year SBI MCLR	MGVCL	DGVCL	UGVCL	TPL-DA	TPL-DS
2011-12	9.39%	9.10%	9.74%	9.23%	8.10%		

FY	PGVCL	1-year SBI MCLR	MGVCL	DGVCL	UGVCL	TPL-DA	TPL-DS
2012-13	9.39%	9.82%	10.48%	10.23%	9.76%		
2013-14	9.02%	9.83%	9.56%	10.24%	9.19%		
2014-15	9.53%	10.00%	8.51%	10.27%	9.28%		
2015-16	8.09%	9.71%	9.46%	13.16%	7.27%		
2016-17	9.26%	8.81%	8.37%	10.49%	9.93%	11.21%	11.12%
2017-18	9.69%	8.00%	9.26%	11.75%	9.96%	8.54%	8.54%
2018-19	9.07%	8.39%	6.13%	11.01%	9.69%	8.69%	8.66%
2019-20	9.71%	8.17%	6.15%	10.88%	8.30%	8.94%	9.07%
2020-21	10.94%	7.11%	6.30%	10.76%	8.20%	7.84%	7.94%
2021-22		7.00%	11.88%	10.69%		7.27%	7.58%
2022-23	14.72%	7.79%	12.29%		14.60%		

4.8.9 Based on the above rates, spread has been computed as shown in table below in line with 1-year SBI MCLR rate for various state DISCOMS

Table 4: Difference in Weighted Average Interest Rate in comparison to 1-Yer SBI MCLR

FY	1-year SBI MCLR	PGVCL	MGVCL	DGVCL	UGVCL	TPL-DA	TPL-DS
2016-17	8.81%	0.45%	-0.44%	1.68%	1.12%	2.40%	2.31%
2017-18	8.00%	1.69%	1.26%	3.75%	1.97%	0.54%	0.54%
2018-19	8.39%	0.68%	-2.26%	2.62%	1.30%	0.30%	0.27%
2019-20	8.17%	1.54%	-2.02%	2.71%	0.13%	0.77%	0.90%
2020-21	7.11%	3.83%	-0.81%	3.65%	1.10%	0.73%	0.83%
2021-22	7.00%	-7.00%	4.88%	3.69%	-7.00%	0.27%	0.58%
2022-23	7.79%	6.93%	4.50%		6.81%		

4.8.10 As evident from the table above, the spread margin over and above the average one-year SBI MCLR has varied between 50 to 150 basis points except for few years and DGVCL. Similarly, for MGVCL, the spread margin has mostly remained negative. Therefore, the Commission has decided to consider the band as one-year SBI MCLR plus 50 basis points to one-year SBI MCLR plus 150 basis points. It will allow the utilities who have raise finance efficiently to earn some incentive as per gain sharing regulations and to present an opportunity to the utilities faring worse to bring their cost of debt within the prescribed band.

4.8.11 For the simplicity, the weighted average rate of interest shall be considered as one-year SBI MCLR plus 50 basis points for the utilities who doesn’t have any actual loan in their books of accounts, however, the normative loan is still there. Further, wherein one-year SBI MCLR is mentioned, the rates as declared by SBI from time to time being in effect applicable for one year shall be taken into consideration.

Final Draft Regulations

4.8.12 In view of the discussion in the foregoing paragraphs, the Commission proposes the following provision for Interest and finance charges in the draft Regulations:

"33 Interest and finance charges

33.1 The loans arrived at in the manner indicated in Regulation 32 of these Regulations on the assets put to use prior to April 01, 2024, shall be considered as gross normative loan for calculation of interest on loan:

Provided that interest and finance charges on capital works in progress shall be excluded:

Provided further that in case of de-capitalisation or retirement or replacement of assets, the loan capital approved as mentioned above, shall be reduced to the extent of outstanding loan component of the original cost of the de-capitalised or retired or replaced assets, based on documentary evidence.

33.2 Normative loan outstanding as on April 01, 2024, shall be worked out by deducting the cumulative repayment as admitted by the Commission up to March 31, 2024, from the gross normative loan.

33.3 Repayment for the year during the Control Period from FY 2024-25 to FY 2028-29 shall be deemed to be equal to the depreciation allowed for that year, attributable towards the assets put to use prior to April 01, 2024, subject to maximum of outstanding normative loan and any normative loan addition during the year.

33.4 Notwithstanding any moratorium period availed by the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed.

33.5 Rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to Generating Company or Transmission Licensee or SLDC or Distribution Licensee:

Provided that at the time of truing up, the weighted average rate of interest calculated on the basis of the actual loan portfolio during the year applicable to Generating Company or Transmission Licensee or SLDC or Distribution Licensee, corresponding to the regulated business, shall be considered as the rate of interest:

Provided that the normative weighted average rate of interest shall be allowed based on actual weighted average rate of interest, if it varies between one-year

SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 50 basis point and one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 150 basis points during the year:

Provided further that if actual weighted average rate of interest exceeds one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 150 basis points, then the normative weighted average rate of interest shall be restricted to one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 150 basis points during the year:

Provided further that if the Petitioner is able to achieve actual weighted average rate of interest less than one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 50 basis points, then the normative weighted average rate of interest shall be allowed as per actual weighted average rate of interest and the net savings on account of efficient financing shall be shared between the beneficiaries and the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, in the ratio of 50:50:

Provided further that if there is no actual loan, corresponding to the regulated business, for a particular year but normative loan is still outstanding, one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 50 basis points, as determined by the Commission in the Order, shall be considered.

33.6 Interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest:

Provided that at the time of truing up, the normative average loan of the year shall be considered on the basis of the actual asset capitalisation approved by the Commission for the year.

Provided further that neither penal interest nor overdue interest shall be allowed for computation of tariff.

33.7 Excess interest during construction on account of time and/or cost overrun as compared to the approved completion schedule and capital cost or on account of excess drawal of the debt funds disproportionate to the actual requirement based on Scheme completion status, shall be allowed or disallowed partly or fully on a case to case basis, after prudence check by the Commission based on the justification to be submitted by the Generating Company or Transmission Licensee or Distribution Licensee along with documentary evidence, as applicable:

Provided that where the excess interest during construction is on account of delay attributable to an agency or contractor or supplier engaged by the Generating Entity or the Transmission Licensee, any liquidated damages recovered from such agency or contractor or supplier shall be taken into account for computation of capital cost:

Provided further that the extent of liquidated damages to be considered shall depend on the amount of excess interest during construction that has been allowed by the Commission:

Provided also that the Commission may also take into consideration the impact of time overrun on the supply of electricity to the concerned Beneficiary/ies.

33.8 Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, in the ratio of 50:50:

Provided in case of SLDC, this provision shall be applicable only to those Intra-State entities who are availing long-term or medium term services of SLDC:

Provided that refinancing shall be allowed if the resultant weighted average rate of interest is below one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for one year period) plus 150 basis point:

Provided further that if the existing weighted average rate of interest exceeds one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for one year period) plus 150 basis point, the refinancing gains shall be computed based on resultant weighted average rate of interest vis-à-vis one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 150 basis point:

Provided further that if the resultant weighted average rate of interest is below one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 50 basis point, the refinancing gains shall be computed based on existing weighted average rate of interest vis-à-vis one-year SBI MCLR (or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period) plus 50 basis point:

Provided further that refinancing shall not be done if it results in increase in rate of interest of existing loan:

Provided also that the re-financing shall not be subject to any adverse terms and conditions and additional cost:

Provided also that Generating Company or Transmission Licensee or Distribution Licensee or SLDC, as the case may be, shall submit documentary evidence of the costs associated with such re-financing:

Provided also that the net savings in interest shall be computed after factoring all the terms and conditions, and based on the weighted average rate of interest of actual portfolio of loans taken from Banks and Financial Institutions recognised by the Reserve Bank of India for Indian institutions, before and after re-financing of loans:

Provided also that the net savings in interest shall be calculated as an annuity for the term of the normative loan, and the annual net savings shall be shared between the Licensee and Beneficiaries in the specified ratio:

Provided further that if refinancing is done and results in decrease in interest rate but negative saving due to higher refinance cost, then the refinance cost to be allowed to the extent of Net Present Value (NPV) of the saving from decrease in interest cost and deduction of refinance cost results into ZERO."

4.9 Depreciation

4.9.1 Under clause 5 (c) of the Tariff Policy notified by the Ministry of Power in 2016 the rates of depreciation notified by the Central Commission would be applicable for tariff as well as accounting and there should be no need for any advance against depreciation. The GERC MYT Regulations, 2016 have specified a straight-line method for determination of depreciation expenses for Generation Companies, Transmission licensees, Distribution Licensees and SLDCs, a salvage value of 10% of the allowable capital cost and depreciation shall be allowed up to a maximum of 90% of the allowable capital cost of the asset, in line with the CERC regulations.

4.9.2 As per Regulation 39 of GERC MYT Regulation, 2016, any asset gets the depreciation at specified rates for the first 12 years of its life and the remaining depreciation is spread out for the remaining useful life of the assets until a residual value of 10% remains. This higher rate of depreciation leads to front loading of the tariff in the initial years. Given the availability of external loans for a 15-18 year tenure, it is necessary to calculate a new rate of depreciation to account for this extended loan period. This will help reduce the rate of depreciation in the early years and counter the impact of front-loading of tariffs.

Issues Discussed in Discussion Paper

4.9.3 The issues discussed and brought up in the Discussion paper for further stakeholder Comments are as follows:

4.9.4 GERC MYT Regulations, 2016 has specified 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%. The asset wise depreciation rate for the first 12 years is specified in the Regulation, and the remaining depreciable value of an asset as on 31st March of the year closing after a period of 12 years from the date of commercial operation is to be spread over the balance useful lie of that asset. Further, the repayment of loan has also been considered on normative basis and has been considered equal to the annual depreciation allowed

4.9.5 It is agreed that, as per prevailing provisions depreciation are skewed in the initial 12years, even though the life of most of the assets is in the range from 25 to 40 years. Further, considering the revised loan tenure of 15-18 years, it is prudent to revise the period for accelerated depreciation from 12 years to 15 years. 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. Accordingly, the depreciation rates shall be revised in line with the revision of normative loan tenure to 15 years.

Suggestion/Comment from Stakeholders:

1) **Adani Power Limited** has requested the Committee

a. to keep the existing 12-year period and if the tenure of 15 years is to be considered it should be applied only to new projects otherwise it will impair the debt service of existing loans whose tenure is 12 years.

b. that if salvage value is considered nil then depreciation shall be allowed for 100% of the capital cost of IT equipment.

c. In case equity base is reduced then investors may not have any motivation to run the plant after useful life therefore increasing the cost. Hence it is requested to continue RoE computation without reducing any equity after completion of useful life of an asset.

2) **MPSEZ Utilities Limited** has submitted that

a. After initially proposing the same CERC in the draft Tariff Regulations, 2019 has dropped the proposal based on stakeholder comments in final regulations and hence the 15-year duration for depreciation calculation should not be mandated in the Regulations.

b. MUL has also commented that reduced equity base will lead to lack of motivation on account of investor to keep the utility running after useful life which will lead to decreased investor certainty citing Appellate tribunal judgement dated 16 May,2006. Hence, it is requested to continue RoE computation without reducing any equity.

3) **GUVNL** has pointed out that since O&M expenses are low in the initial years with higher values at the later stages the same gets compensated by higher depreciation in the initial 12 years and the remaining depreciation value being spread in remaining useful life. the approach to revise the depreciation rates considering the normative loan tenure of 15 years may not be feasible for existing projects. However, same may be considered for the new projects which may be commissioned during the 4th control period of MYT.

Commission's View:

4.9.6 In view of the findings brought forth by the CERC, it has been agreed that since useful life of most assets is 25 to 40 years and prevailing provisions for depreciation are skewed for the initial 12 years, it is prudent to revise the period for higher depreciation from 12 years to 15 years and staying in line with the Tariff Policy. The depreciation rates specified by the CERC should be adopted for generation and transmission and may be adopted for distribution after suitable modification as specified in Section 6.5 by the Forum of Regulators in Evolving Principles of Depreciation for Distribution Assets and Operating and Financial norms for Distribution Study of 2021.

4.9.7 For the purpose of this demonstration, the Commission is considering the details as follows:

Particulars	**Value**
Capital Cost	100
Loan	70
Equity	30
Total Depreciable value	90
Loan component	63
Equity Component	27

a) Scenario 1 – Loan Tenure of 12 Years and accelerated Depreciation for 12 Year

Table 5: Scenario 1 – Loan Tenure of 12 Years and accelerated Depreciation for 12 Year

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Depreciation	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17
Interest on loan	4.97	4.58	4.19	3.80	3.42	3.03	2.64	2.26	1.87	1.48	1.10	0.71	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10.22**	**9.83**	**9.44**	**9.05**	**8.67**	**8.28**	**7.89**	**7.51**	**7.12**	**6.73**	**6.35**	**5.96**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**	**1.17**

- WACC considered for the computation of NPV is 9.36%. NPV in this case comes out to be ₹63.89

b) Scenario 2 – Loan Tenure of 12 Years and accelerated Depreciation for 15 Year

Table 6: Scenario 2 – Loan Tenure of 12 Years and accelerated Depreciation for 15 Year

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Depreciation	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35
Interest on loan	5.00	4.69	4.39	4.08	3.77	3.46	3.15	2.84	2.53	2.22	1.91	1.60	1.29	0.98	0.67	0.47	0.37	0.27	0.17	0.07	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**9.20**	**8.89**	**8.59**	**8.28**	**7.97**	**7.66**	**7.35**	**7.04**	**6.73**	**6.42**	**6.11**	**5.80**	**5.49**	**5.18**	**4.87**	**1.82**	**1.72**	**1.62**	**1.52**	**1.42**	**1.36**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**

- WACC considered for the computation of NPV is 9.36%. NPV in this case comes out to be ₹62.93

c) Scenario 3 – Loan Tenure of 15 Years and accelerated Depreciation for 15 Year

Table 7: Scenario 3 – Loan Tenure of 15 Years and accelerated Depreciation for 15 Year

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Depreciation	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35
Interest on loan	6.02	5.65	5.28	4.91	4.53	4.16	3.79	3.41	3.04	2.67	2.30	1.92	1.55	1.18	0.81	0.56	0.44	0.32	0.20	0.08	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10.22**	**9.85**	**9.48**	**9.11**	**8.73**	**8.36**	**7.99**	**7.61**	**7.24**	**6.87**	**6.50**	**6.12**	**5.75**	**5.38**	**5.01**	**1.91**	**1.79**	**1.67**	**1.55**	**1.43**	**1.36**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**

- WACC considered for the computation of NPV is 9.36%. NPV in this case comes out to be ₹68.36

4.9.8 It can be seen through this exercise that increasing the loan tenure can have a positive effect on the front loading of tariff.

4.9.9 Considering the comments from multiple stakeholders the Commission is of the view that the investments in the sector were made considering an accelerated depreciation for the period of 12 years and since there might be an added premium on the loans accounting for the higher duration. The Commission has decided to keep the existing framework for a higher rate of depreciation for the period of 12 years to maintain the pace of investments in the sector.

4.9.10 Due to high obsolescence and shorter life span of the IT Assets the salvage value for IT equipment and software shall be considered as NIL and 100% value of the asset shall be allowed as depreciable. The regulation has also been amended to include that in case of hydro generating station, the salvage value shall be as provided in the agreement if there is one signed by developers and the State Government

4.9.11 It has been agreed by the Commission that Land other than land under lease and land for reservoir in case of hydro generating station is not to be considered in the calculation of Depreciation since the useful life of land is considered to be infinity and similarly while calculating the Depreciation the value of land should thus be deducted from the Capital Cost of the Project.

4.9.12 Depreciation will be re-calculated during true-up for assets capitalised at the time of True-Up, based on prudence check by the Commission to ensure that the depreciation is calculated proportionately from the date of capitalization.

4.9.13 Further, commission has introduced 3 scenarios in case of Generating station with Emission Control system and added them as regulations 37.2 (c) & (d). Introduction of these regulations is in line with the CERC Tariff Regulation for 2019-24.

Final Draft Regulations

4.9.14 In view of the discussion in the foregoing paragraphs, the Commission proposes the following provision for Depreciation in the draft Regulations:

*"**37 Depreciation***

37.1 The value base for the purpose of depreciation shall be the Capital Cost of the asset admitted by the Commission.

37.2 Generation Company or Transmission Licensee or SLDC or Distribution Licensee shall be permitted to recover depreciation on the value of fixed assets used in their respective Business computed in the following manner:

(a) 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:

(c) Where the Emission Control System is implemented within the original scope of the generating station and the date of commercial operation of the generating station or unit thereof and the date of operation of the Emission Control System are the same, depreciation of the generating station or unit thereof including the Emission Control System shall be computed in accordance with Clauses (a) to (c) of this Regulation.

(d) Depreciation of the Emission Control System of an existing or a new generating station or unit thereof where the date of operation of the emission control system is subsequent to the date of commercial operation of the generating station or unit thereof, shall be computed annually from the date of operation of such emission control system based on straight line method, with salvage value of 10%, over a period of –

i. Twenty-five years, in case the generating station or unit thereof is in operation for fifteen years or less as on the date of operation of the emission control system; or

ii. balance useful life of the generating station or unit thereof plus fifteen years, in case the generating station or unit thereof is in operation for more than fifteen years as on the date of operation of the emission control system; or

iii. ten years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher, in case the generating station or unit thereof has completed its useful life.

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:

Provided that the rate provided in Annexure I, are the upper ceiling of the rate of depreciation to be provided up to 12th year from the date of COD and Generating Company or Transmission Licensee or SLDC or Distribution Licensee, as the case may be, shall have the option of indicating, while seeking approval for tariff, lower rate of depreciation, subject to the aforesaid ceiling and the same will be considered for computation of normative loan as per Regulation 33 of these Regulations.

Provided further that for Generating Company or Transmission Licensee or SLDC or Distribution Licensee formed as a result of a Transfer Scheme, the depreciation on assets transferred under the Transfer Scheme shall be charged as per rates specified in these Regulations for a period of 12 years from the date *of the Transfer Scheme, and thereafter depreciation will be spread over the balance useful life of the assets:*

Provided also that the depreciation already charged after the date of the Transfer Scheme, shall not be restated:

Provided also that Generating Company or Transmission Licensee or SLDC or Distribution Licensee, shall submit all such details or documentary evidence, as may be required under these Regulations and as stipulated by the Commission, from time to time, to substantiate the above claims:

Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life or the extended life.

(c) The salvage 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 that Generating Company or Transmission Licensee or SLDC or Distribution licensee shall submit certification from the Statutory Auditor for the capping of depreciation at ninety per cent of the allowable capital cost of the asset;

Provided also that salvage value for IT equipment and software shall be considered as NIL and 100% value of the assets shall be considered depreciable;

Provided that in case of hydro generating station, salvage value shall be as provided in the agreement, if any, signed by the developers with the State Government;

37.3 Land other than land held under lease and 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.

37.4 In case of existing projects, the balance depreciable value as on April 01, 2024, shall be worked out by deducting the cumulative depreciation as admitted by the Commission up to March 31, 2024, from the gross value of the assets.

37.5 In case of projected commercial operation of the asset for part of the year, depreciation shall be calculated based on the average of opening and closing value of asset, approved by the Commission:

Provided that depreciation will be re-calculated during truing-up for assets capitalised at the time of Truing Up of each year of the 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.

37.6 Generation Company or Transmission Licensee or SLDC or Distribution Licensee shall submit the depreciation computations separately for assets added upto March 31, 2024 and assets added on or after April 01, 2024."

4.10 Normative Rate of Interest on Working Capital

4.10.1 Regulation 40 of the GERC MYT Regulations, 2016 specifies working capital requirement separately for coal-based or lignite-fired thermal generating station, open cycle gas turbine/combined Cycle thermal generating stations and hydro generating station, distribution supply & wire business, SLDC & transmission system and the normative interest on working capital is allowed at a rate equal to the State Bank Base Rate (SBBR) as on 1st April of the financial year in which the Petition is filed plus 250 basis points.

4.10.2 Further, during true-up of any year, a rate equal to the weighted average State Bank Base Rate (SBBR) prevailing during the financial year plus 250 basis points is considered.

4.10.3 As mentioned in the discussion paper, majority of the SERCs have adopted the CERCs normative rate, i.e., "1-Yr SBI MCLR + 350 basis points", which is much more relaxed than existing normative rate specified by GERC, with an exception of MERC, where the margin specified is 150 basis points only.

4.10.4 To further solidify the rationale of maintaining a normative rate at 1-Yr SBI MCLR + 350 basis points we can see from the rate of interest for various utilities that the weighted average rate of interest for every year has been under the 1-Yr SBI MCLR + 350 basis points other than a few exceptions. This move will further push the utilities to improve their credit ratings and secure actual loans with lower interest.

Table 8: Bifurcation for Long term loan and Working Capital Loans

Bifurcation for Long term Loans and Working Capital Loans available							
Sr. No.	**Utilities**	**2021-22**	**2020-21**	**2019-20**	**2018-19**	**2017-18**	**2016-17**
1	GSECL	6.34%	6.50%	7.25%	7.75%	7.75%	9.50%
No Bifurcation for Long term Loans and Working Capital Loans available							
Sr. No.	**Utilities**	**2021-22**	**2020-21**	**2019-20**	**2018-19**	**2017-18**	**2016-17**
1	MGVCL	12.29%	11.88%	6.30%	6.15%	6.13%	9.26%

2	TPL-DA	7.30%	8.00%	9.01%	8.69%	8.54%	10.51%
3	TPL-DS	7.30%	7.99%	8.96%	8.80%	8.55%	11.16%
4	TPL-DD	7.30%	7.93%	9.09%	8.70%	8.55%	11.27%
5	GIFT PCL	6.68%	8.15%	8.91%	8.84%	9.96%	10.88%
1Yr SBI MCLR+150bp		**8.50%**	**9.45%**	**10.15%**	**9.65%**	**9.50%**	**10.70%**

Commission's View:

4.10.5 The Commission is of the view that the utilities have been able to obtain funds at rates which are lower than or around the SBI MCLR plus 100 basis points.

4.10.6 Further, the interest rates for long term loans are generally higher than the working capital loans. Therefore, considering that the normative rate of interest for loans is proposed at 1-Yr SBI MCLR + 100 basis points and that switching from the normative interest rate of 1-Yr SBI MCLR + 350 basis points to 1-Yr SBI MCLR + 100 basis points could be too stringent on the utilities, the Commission has proposed the normative interest rate of 1-Yr SBI MCLR + 150 basis points.

4.10.7 Accordingly, the following clauses are proposed in the draft GERC MYT Regulations, 2023:

"38.7 Rate of interest on Working Capital

38.7.1 Interest on working capital shall be allowed at a rate equal to the State Bank Base Rate (SBBR) / 1 year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) / any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable as on 1st April of the financial year in which the Petition is filed plus 150 basis points:

Provided that at the time of truing up for any year, interest on working capital shall be allowed at a rate equal to the weighted average State Bank Base Rate (SBBR) / 1 year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) / any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable prevailing during the financial year plus 150 basis points."

4.11 Delayed Payment Surcharge

4.11.1 Regulation 43 of GERC MYT Regulation, 2016 states as follows:

"43. Delayed Payment Surcharge

In case the payment of bills of generation tariff or transmission charges or by the beneficiary or beneficiaries is delayed beyond the due date, late payment surcharge at the rate of 1.25% per month on billed amount shall be levied for *the period of delay by the Generating Company or the Transmission Licensee, as the case may be."*

4.11.2 Ministry of Power, Government of India, has issued the Electricity (Late Payment Surcharge and Related Matters) Rules, 2022. Accordingly, the Commission has proposed to reduce the ceiling rate of Delayed Payment Charges and link it to Marginal Cost of Funding Lending Rate. The rate of Interest on Working Capital has been specified as MCLR plus 150 basis points. The Delayed Payment Charges rate proposed are higher than the rate of Interest on Working Capital.

4.11.3 In view of Electricity (Late Payment Surcharge and Related Matters) Rules, 2022, the Commission proposes the following provisions for Delayed Payment Surcharge in the draft Regulations:

"41 Delayed Payment Surcharge

41.1 In case the payment of bills of Generation Tariff or Transmission Charges or SLDC Fees and Charges by the Beneficiary is delayed beyond the due date, Delayed Payment Charge at the Base Rate of Delayed Payment Charges shall be payable on the payment outstanding for the first month of default, notwithstanding anything to the contrary as may have been stipulated in the Agreement or Arrangement with the Beneficiaries:

Provided that the 'Base Rate of Delayed Payment Charges' shall mean the one-year Marginal Cost of Funds-based Lending Rate ('MCLR') as declared by the State Bank of India, as applicable on the 1st April of the financial year in which the period lies, plus five percent and in the absence of MCLR, any other rate as specified by the Commission from time to time:

Provided further that if the period of default lies in two or more financial years, the aforementioned 'Base Rate of Delayed Payment Charges' shall be calculated separately for the periods falling in different years:

Provided that the rate of Delayed Payment Charge for the successive months of default shall increase by 0.5 percent for every month of delay subject to the condition that the Delayed Payment Charge shall not be more than three percent higher than the aforementioned 'Base Rate of Delayed Payment Charges' at any time:

Provided further that the rate at which Delayed Payment Charge shall be payable, shall not be higher than the rate of Late Payment Surcharge specified in the Agreement, if any.

41.2 All payments by a Distribution Licensee to a Generating Company for power procured from it or by a user of a transmission system to a Transmission

Licensee shall be first adjusted towards Delayed Payment Charge and thereafter, towards monthly charges, starting from the longest overdue bill.

41.2.1In case the Distribution Licensee has communicated, in writing, to the Generating Company or Transmission Licensee, as the case may be, the outstanding dues and number of installments in which, the outstanding dues would be paid, within thirty days of the notification of the Late Payment Surcharge Rules, 2022, the following conditions shall be applicable:

(a) The Distribution Licensee may make payment in a month more than the equated monthly installment for the month;

(b) The payment of installment shall be done to all the concerned Generating Companies and Transmission Licensees, as the case may be, on pro-rata basis, depending upon the proportion of their individual outstanding dues.

41.2.2. Notwithstanding anything contained in Regulation 41.1, if the Distribution Licensee agrees to payment of the arrears dues as per the instalment fixed under the Late Payment Surcharge Rules, 2022, and makes timely payment of these instalments, then the Delayed Payment Charge shall not be payable on the outstanding dues.

41.2.3 In case of delay in payment of an instalment under Clause (1), Delayed Payment Charge shall be payable on the entire outstanding dues as on the date of notification of the Late Payment Surcharge Rules, 2022."

41.3 All the bills payable by a Distribution Licensee to a Generating Company or a Transmission Company shall be time tagged with respect to the date and time of submission of the bill and the payment made by the Distribution Licensee shall be adjusted first against the oldest bill and then to the second oldest bill and so on, so as to ensure that payment against a bill is not adjusted unless and until all bills older than it have been paid for:

Provided that any adjustment towards Delayed Payment Charge shall be done in the manner as specified in Regulation 41.2.

Provided that such Delayed Payment Charge and Interest on Delayed Payment earned by the Generating Company or the Licensee or SLDC shall not be considered under its Non-Tariff Income.

Provided further that such Delayed Payment Charge paid or payable by the Distribution Licensee to the Generating Company or the Transmission Licensee or SLDC shall not be allowed as an expense for such Distribution Licensee.

41.4 Late payment surcharge for the retail consumer shall be recoverable as per the terms mentioned in the respective Tariff Orders for the Distribution Licensees."

5 GENERATION

The section discusses the regulatory provisions regarding the terms and conditions for determination of tariff for generating companies supplying power to the Distribution Licensees from conventional generation projects in the State of Gujarat.

5.1 Background

5.1.1 The relevant provisions of Section 62 of the Electricity Act, 2003, in the state of Gujarat, is applied for implementing the tariff determination process for generating companies in the state i.e. Gujarat State Electricity Company Limited (GSECL) and Torrent Power Limited - Generation Business (TPL-G). These companies owns and operate coal, lignite, gas and hydel based generating stations for supplying power to Distribution Licensees in the state on a long-term basis. The section 62 empowers the Commission with the functions of regulating the tariff for generating stations. Further, the power procured by the distribution licensees from Central Generating Stations and Private IPPs, doesn't fall under the purview of the Commission for determination of Tariff.

5.1.2 GSECL owned and operated the following generating stations as on 1st April, 2023:

- Coal based thermal generating stations at Ukai, Gandhinagar, Wanakbori and Sikka;
- Lignite fired thermal station at Panandhro, Kutch;
- Gas fired stations at Utran and Dhuvaran;
- Major hydel stations at Ukai and Kadana and mini hydel stations at Panam, solar power plants at Gandhinagar, Sanand canal, Charanka, KLTPS, Dhuvaran and Sikka TPS and windmills at Layza.

5.1.3 The summary of Generating Stations owned and operated by GSECL are given in the following table:

Table 9: Generating Stations of GSECL

Generating Station	Unit No.	Capacity of the Unit (Mw)	Date Of Commissioning
UKAI (3-5)	3	200	21/01/1979
	4	200	11/09/1979
	5	210	30/01/1985
	Sub-Total	610	
GANDHINAGAR (3-4)	3	210	20/03/1990
	4	210	20/07/1991
	5	210	17/03/1998

Generating Station	Unit No.	Capacity of the Unit (Mw)	Date Of Commissioning
	Sub-Total	630	
WANAKBORI	1	210	23/03/1982
	2	210	15/01/1983
	3	210	15/03/1984
	4	210	09/03/1986
	5	210	23/09/1986
	6	210	18/11/1987
	7	210	31/12/1998
	Sub-Total	1470	
KLTPS	3	75	31/03/1997
	4	75	20/12/2009
	Sub-Total	150	
DHUVARAN	7 – GAS	106.617	28/01/2004
	8 – GAS	112.45	01/11/2007
	Sub-Total	219.067	
UTRAN EXTENSION	GT -1	374.571	08/11/2009
SIKKA TPS 3&4	3	250	14/09/2015
	4	250	28/12/2015
	Sub-Total	500	
UKAI TPS Extension 6	6	500	08/06/2013
DHUVARAN (GAS)	3	376.1	21/05/2014
BLTPS	1	250	16/05/2016
	2	250	27/03/2017
	Sub-Total	500	
WANAKBORI 8 TPS	1	800	13/10/2019
	Sub-Total GSECL (COAL + LIGNITE)	5160	
Sub-Total GSECL (GAS)		970	
Total GSECL (THERMAL)		6130	
UKAI HYDRO	1	75	08/07/1974
	2	75	13/12/1974
	3	75	22/04/1975
	4	75	04/03/1976
	Sub-Total	300	
UKAI LBC	1	2.5	08/12/1987

Generating Station	Unit No.	Capacity of the Unit (Mw)	Date Of Commissioning
	2	2.5	19/02/1988
	Sub-Total	5	
KADANA HYDRO	1	60	31/03/1990
	2	60	02/09/1990
	3	60	03/01/1998
	4	60	27/05/1998
	Sub-Total	240	
PANAM	1	1	24/03/1994
	2	1	31/03/1994
	Sub-Total	2	
Sub-Total GSECL (Hydro)		547	
WIND MILLS	LAYZA	10	04/01/2009
SOLAR	PLANT AT GTPS YARD	1	27/03/2012
	PLANT AT SANAND BR. CANAL	1	29/03/2012
	CHARANKA	10	23/03/2015
	KLTPS	1	02/05/2016
	SIKKA TPS	1	02/05/2016
	DHUVARAN I	75	05/02/2019
	CHANDARVA	30	28/08/2021
	DHUVARAN II	75	15/04/2021
Total GSECL as a whole		6881	

5.1.4 TPL-G (APP) has existing coal based thermal power generating facilities with total installed capacity of 362 MW at Sabarmati, Ahmedabad that consist of 3 units viz. D-Station (120 MW), E-Station (121 MW) and F-Station (121 MW).

5.1.5 The summary of Generating Stations of GSECL and TPL-G is given in the following Tables:

Table 10: Generating Station of TPL-G

Generating Station	Capacity in MW	Unit No.	Year of Commissioning
Sabarmati ‘D’	120	1	1978/2004* (*Upgrading Capacity)
Sabarmati ‘E’	121	1	1984
Sabarmati ‘F’	121	1	1988
Total	362		

5.1.6 The norms for determining the tariff for the Generating Stations is proposed to be determined using a performance-based approach linked to operational parameters.

5.1.7 As evident from the above tables, it is observed that most of the generating stations have already completed their useful life, and few will be completing their useful life in the proposed fourth MYT Control Period. Therefore, the target for operational performance parameters of generating stations have been proposed to be considered after duly considering the aging factor for respective stations.

5.1.8 The Section 61 of the Electricity Act, 2003 and the National Tariff Policy, provides for taking guidance from principles and methodologies as specified by the Central Electricity Regulatory Commission for specifying terms and conditions for determination of Tariff by SERC. Accordingly, the Commission has adopted the methodology/or amendments proposed by CERC in their approach paper (wherever required with necessary changes) while specifying the terms and conditions in the draft GERC MYT Regulations, 2023.

5.1.9 A Hybrid approach, i.e., Cost plus and Performance based approach is proposed to be adopted for to determine terms and conditions for Generation tariffs. Accordingly, the Performance of the utilities will be linked to operational parameters and certain component of the cost, which would be used to provide incentives based on actual performance considering the controllable factor and other few cost parameters as specified in the Regulations will be allowed on actual cost basis along with the Return on Equity.

5.2 Petition for determination of generation tariff

5.2.1 The Regulations 47 of the draft GERC MYT Regulations, 2023, specifies that the Tariff in respect of a Generating Station may be determined Stage-wise, Unit-wise or for the whole Generating Station.

5.2.2 The Generating Company to adopt a reasonable basis for allocation of capital cost relating to common facilities across all Stages or Generating Units which shall be duly audited and certified by the statutory auditor.

5.2.3 In case of new Generating Stations, the final tariff can be determined once the Generating Unit or Plant gets commissioned and the audited capital cost is available. However, it is important that as soon as the plants gets COD and is in operating condition, i.e., supplying electricity to its beneficiaries, the commercial settlement must be undertaken in order to meet the working capital and debt service obligation of the plant. Considering the expected time interval for availability of audited capital cost post commissioning of the plant, there is a practice adopted of determining the provisional tariff in advance so as the commercial billing mechanism is initiated post commissioning of the project so as to provide interim cash flow to meet the operational needs. However, it is noticed that higher the time gap is allowed between determination of provisional tariff and COD of the plant, the resultant variance in the provisional and final tariff is relatively higher, which may either result in under recovery for the Generating Unit / Station or higher burden of tariff on consumers.

5.2.4 Accordingly, CERC, in the CERC Tariff Regulations, 2019 has revised the time period for filing of provisional tariff within 60 days prior to the anticipated date of COD. Such approach will also benefit the beneficiaries and the consumers whereby the deviation between provisional and actual tariff will be on a lower side. However, the Generating Company is free to file the Petition before the deadline of 60 days before anticipated date of COD, so that the provisional tariff is in place when COD happens. Therefore, in accordance with the CERC Tariff Regulations, 2019 the Commission has proposed for reduction of time period for filling of provisional tariff from 180 days to 60 days prior to the anticipated COD in the draft GERC MYT Regulations, 2023.

5.2.5 Also, the Commission is of the view that the details related to completed cost and the audit of such cost of the Generating Units/Stations can be completed within 60 days and accordingly the time period for filing the Petition for final tariff is also proposed to be reduced from 180 days to 60 days from the date of COD.

5.2.6 As per the draft GERC MYT Regulations, 2023, the recovery of the difference between provisionally approved tariff and final tariff, due to difference in provisionally approved capital cost and actual capital cost is clearly specified. Further, for discouraging the applicants from projecting higher capital expenditure, the interest applicable on the recovery of such difference has been specified at a higher rate in case the actual capital expenditure is lower than the approved projected capital expenditure. However, in case where the actual capital expenditure exceeds the provisionally approved capital expenditure, the interest specified are comparatively lower.

5.2.7 It is specified in the GERC MYT Regulations, 2016 that in case actual capital cost incurred is lesser than the approved capital cost by 5% or more, the Generation Company to refund to the beneficiaries, the excess tariff realized along with interest at 1.20 times of the Base Rate of State Bank of India plus 350 bps. Further, if actual capital cost incurred is higher by 5% or more, the Generation Company shall be entitled to recover from the beneficiaries, the shortfall in tariff along with interest at 0.80 times of the Base Rate of State Bank of India plus 350 bps.

5.2.8 In the draft GERC MYT Regulations, 2023, it is proposed that the deviation between actual and approved capital expenditure may be continue with 5%, however, the spread on interest rate may be considered as 150bps linked to Base rate as defined paras above, considering the present market conditions.

5.3 Fuel Utilization Plan

5.3.1 Flexibility in Generation and Scheduling of Thermal Power Stations schemes was introduced by Ministry of Power, vide letter dated 5th April 2018 to promote bundling of cheaper Renewable Energy (RE) with costlier Thermal Power and to promote Renewable Purchase Obligation (RPO) of Distribution Licensees. Subsequently, MoP vide order dated 12.04.2022, revised the Scheme for flexibility in generation and scheduling of Thermal/ Hydro Power Stations through bundling with Renewable Energy and Storage Power. According to the scheme, the bundled RE Power (with or without ESS) shall be supplied to the beneficiaries at a tariff which shall be less than ECR of the generating station. Such a tariff would include the balancing cost and the tariff risk has to be borne by the Generator. The net savings realized, if any, from supply of RE power instead of Thermal or Hydro power under existing PPA shall be passed on to the beneficiary by the generating company on a monthly basis in the ratio of 50:50.

5.3.2 Considering the multiple long-term contracts with different FSA and coal linkages for each Generating Unit/Station, Ministry of Power, through CEA (Fuel Management Division) had notified “Methodology for flexibility in utilization of domestic coal for reducing the cost of power generation” dated June 8, 2016. Wherein, the methodology has been specified for utilization of domestic coal in a flexible manner by Central/State GENCOs and IPP’s for reducing cost of power generation by minimizing the transportation cost and optimum utilization of coal. In this methodology, there are five case envisaged for allowing flexibility of utilization of coal under this arrangement, which are as follows:

- Case-1: Use of Coal aggregated with the State in its own State Generating Stations.
- Case-2: Use of Coal aggregated with the one State in Generating Stations of other State’s utilities.
- Case-3: Use of Coal aggregated with State in Central Generating Stations and vice versa.
- Case-4: Use of Coal by any State / Central Generating Company in Private Generating Stations (IPPs).
- Case-5: Use of coal assigned to the Central Generating Company in their own plants or any other more efficient plants.

5.3.3 The basic objective of this policy is to have a flexibility in utilization of coal in an efficient manner so as to optimize the cost. By giving cognizance to the options provided in this methodology, the Commission is of the view that a Generating

Company needs to evaluate various scenarios of utilization of coal in different Generating Stations. It must have an efficient annual coal utilization plan so as to optimize the cost and lower the burden of tariff on the consumers. The basic objective is that the Generating Company needs to indicate minimum total variable cost of all plants together so as to achieve optimization by not running all plants but running only efficient plants having least variable cost. However, such optimization plan may not be limited to coal and can be considered for any fuel such as coal, gas, naphtha, lignite, etc.

5.3.4 Accordingly, the Generating Companies will be required to have a long-term Station wise generation plan, and a plan for sourcing the required quantum of different fuels, with a view to optimize utilization of coal and to reduce the variable cost of generation, so as to benefit the consumer. Also, in order to acknowledge the implementation of Case 1 as well as Case 4 under flexible utilization of coal policy, the Commission has proposed for introduction of regulations regarding Fuel utilization plan as reproduced below:

*"**47. Fuel Utilization Plan***

47.1. The Generating Company shall prepare and submit Fuel Utilization Plan for the Control Period commencing on April 1, 2021, along with the Petition for determination of Tariff for the Control Period from April 1, 2021 to March 31, 2026, in accordance with Chapter 2 of these Regulations, to the Commission for approval.

47.2. The Fuel Utilization Plan should ensure that fuel quantum is allocated to different generating Stations/Units in accordance with the merit order of different generation Stations/Units in terms of variable cost:

Provided that the fuel allocation should be such that, subject to system and other constraints, the least cost generating Stations/Units are operated at maximum availability and other generating Stations/Units are operated at maximum availability thereafter in the ascending order of variable cost

47.3. The Fuel Utilization Plan shall comprise the following:

(a) Forecast of fuel requirement for each unit/station;

(b) Details of contracted source, annual contracted quantity, estimated availability from contracted sources and resultant shortage of fuel, if any, for each unit/station;

(c) Use of optimum mix of fuel;

(d) Alternate arrangement for meeting shortage of fuel along with impact on variable cost of unit/station;

(e) Plan for swapping of fuel source for optimizing the cost, if any, along with detailed justification and cost savings;

(f) Net cost savings in variable cost of each unit, if any, after optimum utilization of Fuel:

Provided that the forecast or estimates for the Control Period from FY 2021-22 to FY 2025-26 shall be prepared for each month over the Control Period:

Provided further that Fuel Utilisation Plan shall be prepared based on past data and reasonable assumptions for future.

The beneficiary/ies shall file comments/suggestions on such Plan during proceedings of Tariff Petition as per Regulation 26.

47.4. Annual Fuel Utilisation plan shall be submitted by the Generating Company each year during the tariff proceedings for the review of the Commission along with the justification for any deviation between the approved fuel utilisation plan and actual Fuel utilisation along with the cost impact from FY 2022-23 onwards.

Provided a Generating Company may, as a result of additional information not previously known or available to it at the time of submission of the Fuel Utilisation Plan under Regulation 49.1, apply for modification in the Fuel Utilisation Plan, during filing of the petition in the remaining part of the Control Period.

Provided at the time of review of the Annual Fuel Utilisation Plan, the Commission may, as a result of additional information not previously known or available to the Commission at the time of approval of the Fuel Utilisation Plan under Regulation 47.1, if it deems appropriate, modify the Annual Fuel Utilisation Plan for the remainder of the Control Period, at the time of annual tariff proceedings."

5.4 Components of tariff

5.4.1 The Regulation 48 of the GERC MYT Regulations 2016, provides for determination of tariff components for sale of electricity from a thermal/hydro Generating Station.

5.4.2 PEG has submitted that the capacities that have completed useful life are likely to play an important role in sector operations, through grid balancing and providing peaking power, given their low fixed cost. Allowing capacity charges of such plants to also be recovered based on scheduled generation (in addition to variable costs) could be explored. But given that such costs are passed through, they should be subject to prudence checks prior to approval. A cap shall be considered on this deemed fixed cost to limit the impact of this cost over and above the energy charge. Additionally, the Commission could also explore setting an upper limit for generation from such capacity to minimise excess generation from sub-optimal plants beyond end of useful life.

5.4.3 The tariff of thermal generating station shall consist of two parts namely Annual Fixed Charges (AFC) for recovery of fixed cost components and Energy Charges (EC) for recovery of primary and secondary fuel cost.

5.4.4 The tariff of Hydro Generating Stations shall comprise of two parts i.e. Capacity Charge (CC) and Energy Charge (EC).

5.5 Annual Capacity Charges

5.5.1 The Commission has proposed the components of Annual Capacity Charges as follows:

"49 Annual Capacity Charges

49.1 The Annual Capacity Charges shall comprise of the following elements:

(i) Depreciation;

(ii) Interest and Finance Charges on Loan Capital & Return on Equity and/or Return on Capital Employed;

(iii) Interest on Working Capital;

(iv) Operation & Maintenance Expenses;

(v) Income Tax

(vi) Special allowance in lieu of renovation & modernisation, wherever applicable;

(vii) SLDC Fees and Charges minus:

(viii) Non-Tariff Income:

Provided that depreciation, interest and finance charges on loan capital & return on equity and/or return on capital employed and interest on working capital and income tax for Thermal and Hydro Generating Stations shall be allowed in accordance with the provisions specified in Chapter 3 of these Regulations:

Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, subject to prudence check:

Provided also that all penalties and compensation payable by the Generating Company to any party for failure to comply with any directions or for damages, as a consequence of the orders of the Commission shall not be allowed to be recovered through the Aggregate Revenue Requirement whereby the details of penalties and compensation paid or payable, if any, is required to be submitted to the Commission along with the Petition under these Regulations."

5.6 Renovation & Modernization

5.6.1 As several thermal as well as hydro generating plants of Gujarat have completed their useful life of 25 and 35 years respectively and a few shall be completing the same in the next control period, the Commission has decided to continue with the provision of opting either Renovation and Modernization (R&M) Expenses or Special Allowance as per Regulations 50 of the GERC MYT Regulations 2016 for improving the performance and encouraging higher efficiency level of the Station.

5.6.2 APL suggested that separate norm of Special Compensation for coastal plants shall be provided based on their historical add cap details. The Generators should be allowed to approach the Commission for approval of new expenses not covered under add cap or special compensation on case to case basis.

5.6.3 FOKIA submitted that old plant-Units whose useful life is over long back shall be de-commissioned or at least no R & M schemes shall be approved and taken up for such over-lived uneconomical machines unless objective cost-benefit studies are made and the benefits established beyond doubt by reputed third party experts to avert capitalization of such wasteful expenses.

5.6.4 The Commission is of the view, that in order to avail such allowances the Generating company shall need to file 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, record of consultation with beneficiaries and any other information considered to be relevant by the Generating Company.

5.6.5 Further, the CERC (Terms and Conditions of Tariff) Regulations, 2019 has removed the escalation factor from the provision of Special Allowance. Therefore, the Commission has decided that Special allowance availed by the Generating Company during the first year of the control period shall continue to be same for the rest of the years of the control period.

5.6.6 However, the option of undertaking R&M instead of fresh capital investment continue to be explored based on a detailed cost-benefit analysis.

5.6.7 The Regulation 50.6 of the GERC MYT Regulations, 2016, allows the Special Allowance @ 7.5 lakh/MW/year for the year 2016-17 and thereafter escalated @ 5.72% every year during the Control Period in accordance with the CERC Tariff Regulations, 2014. CERC in its Tariff Regulations, 2019 has increased the Special Allowance to 9.5 lakh/MW/year. However, the Commission has proposed Special Allowance to be @ Rs. 11.00 lakh/MW/year for the entire control period in the draft GERC MYT Regulations, 2023.

5.7 Norms of operation for Thermal Generating Station

5.7.1 Regulation 53 of the GERC MYT Regulations, 2016, specifies various norms for operation of thermal Generating Station. Each norm of operation has its impact in determination of tariff. The norms and their impact on the tariff are summarized below:

Table 11: Operational norms and their impact on tariff

Sr. No.	Regulation	Norms of Operation
a.	Regulation 53.1	Plant Availability Factor (PAF)
b.	Regulation 53.2	Plant Load Factor (PLF)
c.	Regulation 53.3 & 53.4	Gross Station Heat Rate (SHR)
d.	Regulation 53.5	Secondary Fuel oil Consumption (SFOC)
e.	Regulation 53.6	Secondary Fuel oil Consumption (SFOC)
f.	Regulation 53.7	Auxiliary Energy Consumption (AEC)
g.	Regulation 53.8	Transit and Handling Losses

5.7.2 GSECL has submitted that while reviewing the operational parameters such as auxiliary consumption, Secondary fuel consumption, SHR,PLF etc. Other factors such as deviation from use/ availability of design fuel quality may also be taken into consideration as uncontrollable parameter because during recent past years, huge losses in availability (NAPAF) are observed due to fuel quality related issues.

5.7.3 Prayas (Energy Group) has submitted that an additional relaxation of 2% is allowed on NAPAF on account of coal shortage and sustained uncertainty of coal supply. However, there have been significant improvements in domestic coal supply. This is seen even in GSECL plants, for instance the share of coal receipt to its allocation for Wanakbori TPP (GSECL' biggest plant at 2270 MW) increased from 46.97% in FY20 to 88.18% in FY23. Additionally, the existence of other procurement alternatives such as integrated mines, e-auctions and (soon) commercial mine also reduces the need for such concessions. Therefore, the group requested Commission to consider doing away with the relaxation in availability norms on account of coal shortage.

5.7.4 Further, as understood from the review of tariff orders from FY17 to FY22, the normative availability is approved in the truing up process, despite actuals varying from such norm. The reasoning for such treatment as per the orders is on account of availability being a controllable parameter. It is unclear why the impact on account of slippages in an controllable parameter is being passed through to the consumer. This practice sets a poor precedent as it does not hold generators accountable for not being available as projected, and in periods of peak demand, could result in insufficient capacity to meet demand. The reflection of such availability on fixed cost recovery, in accordance to tariff regulations, is also affected. In the interest of safe guarding consumer interests, setting better precedents, and ensuring proper signaling the Commission should ensure that actual availability is approved and reflected in fixed cost recovery unless such operation is on account of uncontrollable parameters—and even so should not be entertained over extended periods of time.

5.7.5 The group also submitted that review of the other operating norms either on the basis of historical data or through benchmarking using CEA recommendations. While historical data is useful in bringing out trends and developing some understanding of these parameters, only considering such data will potentially result in the carry forward of past inefficiencies. Instead benchmarks and projections should be used to continuously improve performance and improve efficiency of operations in response to dynamic sector changes

5.7.6 The CERC in its Tariff Regulations, 2019, has specified similar norms for each performance parameter for new as well as existing Generating Stations; except for few old Generating Stations of NTPC, NLC, DVC and NEEPCO where a relaxed norms have been specified based on past performance.

5.7.7 The Commission has proposed to adopt a similar approach for specifying the common norms for the Performance parameters, which would be applicable to new as well as existing Generating Stations. Although, relaxed norms have been specified for few Generating Stations based on actual performance of these stations over past period.

5.7.8 While proposing the norms for next Control Period, the Commission has analyzed the past performance of existing Generating Stations. The Commission has sought the relevant data of the performance parameters from the respective Utilities. In case where the Commission observed ambiguity in data submitted, the Commission has considered the respective values as per the Truing up Orders of respective years. The approach adopted for determination of the norms for the performance parameters has been detailed in the corresponding paras below:

5.8 Normative Annual Plant Availability Factor (NAPAF)

5.8.1 Normative Annual Plant Availability Factor (NAPAF) of a Generating Station demonstrate the percentage of time the station is available to provide electricity to grid/beneficiaries. As per the present approach, the recovery of Annual Fixed Charges is based on cumulative availability during the year.

5.8.2 As per Regulation 53.1 of the GERC MYT Regulations, 2016, the target NAPAF for full recovery of Annual Fixed Charges is 85% for all thermal Generating Station except for some existing older Stations of GSECL. The same is also in line with the CERC Tariff Regulations, 2019.

5.8.3 The proviso to Regulation 53.1 (a) of the GERC MYT Regulations, 2016, provides relaxation for full AFC recovery at 83% NAPAF due to coal shortage. The same is also in line with the CERC Tariff Regulations, 2019.

5.8.4 Further, the relaxed norms of PAF were specified for the Generating Stations such as Ukai TPS (Unit 1- 5), Gandhinagar TPS (Unit 1- 4), Wanakbori TPS (Unit 1-6), Sikka TPS, Kutch Lignite (Unit 1-3) and Kutch Lignite (Unit 4). The relaxation was given considering the vintage effect and technology of plant. It was also specified that the Commission may revise the norms for Availability for the above-mentioned Generating Stations in case of Renovation & Modernisation undertaken by the Generating Station.

5.8.5 The Commission has analysed the actual performance parameters of various Generating Stations including those where relaxed norms have been specified over the past period, i.e., from FY 2017-18 to FY 2022-23 against the normative target availability. The following table provides the comparison of actual availability vis-à-vis normative availability for Generating Stations of GSECL and TPL-G based on the data submitted by the utilities:

Table 12: Actual Plant Availability Factor (%) for Thermal Power Generating station

Station	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	Average
Ukai (3-5)	89.62%	82.76%	85.60%	90.64%	69.04%	51.52%	78.20%
Ukai Extn. 6	75.14%	76.72%	83.34%	85.58%	57.22%	60.69%	73.12%
Gandhinagar (3-4)	93.32%	87.62%	94.25%	99.06%	88.61%	71.76%	89.10%
Gandhinagar 5	92.42%	89.88%	92.01%	99.50%	72.96%	69.81%	86.10%
Wanakbori 1-6	86.86%	89.21%	93.91%	94.12%	70.59%	52.21%	81.15%
Wanakbori 7	100.69%	90.24%	97.85%	95.61%	86.07%	77.68%	91.36%
Wanakbori 8	-	-	16.51%	90.44%	70.23%	64.35%	60.38%
Sikka Extn. (3-4)	84.45%	90.28%	93.40%	78.28%	39.23%	83.73%	78.23%
KLTPS 3	65.52%	46.05%	29.54%	76.52%	69.89%	54.66%	57.03%
KLTPS 4	49.12%	44.49%	45.22%	46.23%	8.86%	43.15%	39.51%
BLTPS 1&2	73.71%	35.82%	12.84%	27.57%	33.73%	27.24%	35.15%
Dhuvaran	83.26%	76.27%	58.48%	76.34%	79.00%	89.04%	77.07%

Station	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	Average
CCPP 1							
Dhuvaran CCPP 2	83.26%	76.27%	12.84%	78.91%	76.78%	87.82%	69.31%
Dhuvaran CCPP 3	90.11%	96.02%	68.24%	61.29%	42.22%	95.87%	75.62%
Utran Extension	96.55%	96.74%	91.23%	88.00%	85.55%	95.18%	92.21%
Ukai Hydro	96.55%	96.74%	87.37%	76.62%	85.47%	94.41%	89.53%
Kadana Hydro	92.29%	91.79%	88.91%	90.71%	79.93%	79.15%	87.13%

5.8.6 From the above Table following observations were made:

a) Ukai TPS (3-5): It is observed that Ukai (Unit 1 and 2) were decommissioned in 2016-2017. The Units 3 to 5 of Ukai Station have also outlived its useful life and have been in operation for around 35 to 40 years. However, it is observed that the Ukai TPS (3-5) Station has achieved actual average availability of 78.20% over the past six years from FY 2017-18 to FY 2022-23. Although, during FY 2017-18 to FY 2020-21 the Stations achieved availability of more than 80% and achieved availability of even 90% in FY 2020-21, which is significantly higher than the normative availability of 80.00% approved by the Commission for full recovery of fixed charges in the previous Control Period. However, it is also observed that these Units achieved availability of 69.04% and 51.52% only during FY 2021-22 and FY 2022-23 respectively, which was due to forced outage for 55 days due to turbine bearing replacement and LP rotor repairing work, Capital Overhaul of 65 days in Unit-3 and Annual Overhaul of 31 days for Unit-4. Further, after the decommissioning of Unit 1 & 2, it is observed that the Units 3 to 5 were able to achieve higher availability. Hence, it is proposed to continue with the normative availability for the station as 80% for full recovery of fixed costs.

b) Gandhinagar TPS (3-4): The Units 1 & 2 have been successfully de-commissioned with effect from September 2016. These Units have achieved availability of more than 85% from FY 2017-18 to FY 2022-23, however the actual availability during FY 2022-23 was 71.76% due to Annual Overhauling of 37 days and partial operation due to restriction in coal mill of Unit-4. Hence, it is proposed to continue with the normative availability for the station as 85% for full recovery of fixed costs .

c) Wanakbori TPS (Unit 1-6): It is observed that Wanakbori TPS (Unit 1-6) has achieved average availability of more than 81% since FY 2012-13. It is observed that these Units has been able to achieve actual availability of 97% and 100% also FY 2019-20 and FY 2020-21. Hence, it is proposed to continue with the normative availability for Wanakbori (1-6) TPS as 85% for full recovery of fixed costs.

d) KLTPS (Unit-3): The Units 1 & 2 have been successfully de-commissioned with effect from January 2020. Further, the Unit 3 was commissioned on March 31, 1997, and has completed around 23 years of its useful life. The unit wise availability of KLTPS was not available, however, based on the past year performance, it was observed that actual availability of aforesaid Station remained consistently lower than the normative availability of 75%, except in FY 2016-17 and FY 2020-21. From the past Tariff Orders, it was observed that the reasons for such lower availability as specified by GSECL was on account of Turbine vibrations, problems in Air Pre-Heater (APH), Boiler tube leakage (BTL), and also due to non-availability of coal mills due to poor lignite quality. The Commission is of the view that such consistence under-performance shall not be allowed for any Generating Stations. Further, considering that as older Units, i.e., Unit 1 &2 have now been de-commissioned which might have affected the operational parameters of overall plant and hence, it is expected that post decommissioning of Unit 1 & 2, the performance of standalone Unit 3 will be better than past performance of the Plant as a whole. However, it is observed that the average availability achieved by the Unit has been 46.05%, 29.54%, 76.52%, 69.89% and 54.66% during FY 2018-2019, FY 2019-2020, FY 2020-2021, FY 2021-2022 and FY 2022-2023 respectively, which has been primarily due to reasons such as Inadequate and Poor lignite quality & frequent forced outages/partial operation of units due to non-availability of milling system and Annual overhauling. Therefore, based on the performance in the last five years, it is proposed that the normative availability for Unit-3 as 72.00% (in accordance with CERC 2019 Tariff Regulations) for the next Control Period for full recovery of fixed charges.

e) KLTPS (Unit-4): The actual availability of KLTPS (Unit-4) remained consistently lower than the normative availability of 80%, specified by the Commission in the GERC MYT Regulations, 2016. From the past Tariff Orders, it was observed that during FY 2014-15 the availability was lower due APH and FBHE problem, in FY 2015-16 blockage in Air Pre-Heater (APH) and in FY 2016-17 BTL issue and leakage in FBHE and NMEJ impacted the availability of Station. Further, in FY 2017-18 Seal Pot problem, Cyclone repairing and NMEJ replacement and in FY 2018-19 forced outage and partial outage due to boiler tube leakage, Seal Pot to combustor expansion joint leakage etc. caused the lower availability of Station. Further, the station has been able achieve availability of around 45% in the last five years with average availability of only 8.8% during FY 2021-22 due to forced outage for 286 days for LHS Cyclone outlet Duct work. It was also observed that the actual availability of KLTPS (Unit-4) remained lower than the norms specified in Regulations during previous Control Period. It is to be noted that KLTPS 4 was commissioned on October 22, 2008 and has completed around 12 years of operation only. The Commission is of the view that such consistence under-performance will not be acceptable for any Generating Station especially when there are no prudent reasons for the non-performance and the stations are not old as well. Therefore, based on the performance in the last five years, it is proposed that the normative availability for

Unit-4 as 72.00% % (in accordance with CERC 2019 Tariff Regulations) for the next Control Period for full recovery of fixed charges.

f) Dhuvaran CCPP 2: The actual average availability achieved by Dhuvaran CCPP 2 over the past five year is 69.31%. The station had achieved availability of more than 90% during FY 2012-13 to FY 2015-16. The actual availability of plant was lower than the normative during FY 2016-17 to FY 2021-22 due reasons such as planned outages, non-availability of gas, forced outages due to Gas Turbine Start up problem (SFC) and vacuum related problem caused lower availability, chocking of GT fuel nozzle etc. As, the station has been able to meet the target availability in the past, the Commission has proposed to retain the target availability for the Dhuvaran CCPP-2 station at 85% for next Control Period.

g) Sabarmati (D, E and F): The actual availability of these stations was higher than the NAPAF from FY 2015-16 to FY 2022-23. Hence, it is proposed that the target availability may be retained as follows:

Table 13: Sabarmati Generating Stations Target Availability

Station	Target Availability (%)
D-Station	87.08%
E-Station	92.42%
F-Station	93.49%

h) PPA governed stations: Ukai Extn. (Unit - 6), Gandhinagar (Unit -5), Wanakbori (Unit – 7 and 8), Sikka Extn. (Unit 3-4), Dhuvaran CCPP – 1, Dhuvaran - CCPP 3, Utran Extension and BLTPS (Unit- 1 and 2) are PPA governed stations wherein the target availability shall be governed based on the terms of the respective PPAs.

5.8.7 In view of above, the Commission has proposed to continue with the existing norms which specifies that target availability for full recovery of Annual Fixed Charges for the next Control Period to be 85% for all Thermal Generating Stations including new Generating Stations and stations that have been commissioned during the present Control Period except those covered in the following table:

Table 14: Normative Annual Plant Availability factor

Station	Target Availability (%)
Ukai TPS (Unit 3-5)	80
Kutch Lignite (Unit 3)	72
Kutch Lignite (Unit 4)	72

5.9 Gross Station Heat Rate

5.9.1 The Gross Station Heat Rate (GSHR) of plant is inversely proportional to the efficiency of plant, i.e., if the heat rate is lower, the efficiency is higher. The SHR is a crucial parameter as it has substantial impact on tariff of generating unit. The SHR of plant depends upon various factor such as technology of generating unit, age, unit size, percentage of loading, past generating performance, past maintenance practices, condition of plant, etc.

5.9.2 Regulations 53.3 of the GERC MYT Regulations 2016 specifies the Station Heat Rate (SHR) norm for Existing as well as new Generating units or stations achieving COD after the effectiveness of the Regulations. The SHR of existing thermal Generating Stations of GSECL's and TPL-G's were based on the past data submitted by them. However, for new Generating Units/Stations to be commissioned after the date of effectiveness of the GERC MYT Regulations 2023, the SHR norm are proposed in accordance with the norms specified by the CERC in its Tariff Regulations 2019, for various technologies and Unit sizes as well as considering the technological advances and improvement, with manufacturers' committing design heat rates. In the case of PPA governed stations, the SHR is approved based on the terms of the respective PPAs.

5.9.3 The normative SHR for existing generating station provided in the GERC MYT Regulations, 2016 is shown below:

"53.3 Gross Station Heat Rate – For existing Generating Stations:

a) Thermal Generating Stations of Gujarat State Electricity Generation Company Limited (GSECL):

Table 3: Gross Station Heat Rate for GSECL Stations for the Control Period

/Stations	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
Ukai TPS (Unit 1 - 5)	2750	2750	2750	2750	2750
Gandhinagar TPS (Unit 1 - 4)	2679	2679	2679	2679	2679
Wanakbori TPS (Unit 1 – 6)	2625	2625	2625	2625	2625
Sikka TPS	3008	3003	2998	2993	2988
Kutch Lignite TPS (Unit 1 - 3)	3231	3231	3231	3231	3231
Kutch Lignite TPS (Unit 4)	3000	3000	3000	3000	3000
Dhuvaran CCPP - 2	1950	1950	1950	1950	1950
Ukai-6	2385	2385	2385	2385	2385
Dhuvaran CCPP-3	1850	1850	1850	1850	1850
Sikka 3 & 4	2398	2398	2398	2398	2398

/Stations	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
BLTPS					2623

Provided that the Commission may revise the norms for the Gross Station Heat Rate for the above-mentioned Generating Stations in case of Renovation & Modernization undertaken by the Generating Station;

b) Thermal Generating Units of Torrent Power Limited -Generation Business (TPL-G):

Table 4: Gross Station Heat Rate for TPL-G Stations for the Control Period

Stations	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
Sabarmati 'C'	3136	3136	3136	3136	3136
Sabarmati 'D'	2450	2450	2450	2450	2450
Sabarmati 'E' & 'F'	2455	2455	2455	2455	2455

Provided that the Commission may revise the norms for the heat rate for the above-mentioned Generating Stations in case of Renovation & Modernization undertaken by the Generating Station;"

5.9.4 FOKIA has submitted that GSECL is using 13 % higher quantum of coal by continuing old units resulting in higher fuel cost as also the environment degradation. If unit wise data were furnished for these stations, it would have clearly shown that all old machines/units operating beyond 40+ years since commissioning, were not contributing materially to power generation but kept in operation just to recover the undue Fixed Costs therefrom.

5.9.5 The Commission has been following the consistent practice of formulating norms based on actual data of the past period, which is also in line with the practice followed by the CERC. The Commission also notes that Tariff Policy guidelines suggest that the norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies.

5.9.6 In view of above, the Commission has analysed the actual performance of various Generating Stations over the past year and after considering the factor affecting the Heat Rate as such vintage, size, past generating history, past maintenance practices, condition of plant, etc., has proposed the SHR norms for the next Control Period.

5.9.7 The Table below provides the summary of actual SHR data from FY 2017-18 to FY 2021-22 with respect to GSECL and TPL-G's Generating Stations based on the data submitted by the utilities:

Table 15: Actual Station Heat Rate of Existing Stations/Units (kcal/kWh) for GSECL

Power Station	FY 2017-2018	FY 2018-2019	FY 2019-2020	FY 2020-2021	FY 2021-2022	Average
Ukai (3-5)	2589	2529	2596	2529	2618	2572
Gandhinagar (3-4)	2532	2537	2581	2529	2545	2545
Gandhinagar 5*	2503	2504	2538	2516	2516	2515
Wanakbori 1-6 TPS	2580	2539	2539	2543	2579	2556
Wanakbori 7*	2450	2454	2463	2466	2488	2464
Sikka Extension (3-4)*	2507	2552	2479	2434	2419	2478
KLTPS 3	-	-	-	-	3254	3254
KLTPS 4	2968	3015	3121	3128	3154	3077
BLTPS*	-	-	3365	3196	2969	3177
Dhuvaran CCPP 1*	2122	2091	2138	2097	2202	2130
Dhuvaran CCPP 2	2056	2143	2156	2117	2217	2138
Dhuvaran CCPP 3*	3643	1849	1956	1799	1974	2244
Utran Extension*	1848	1771	1839	1753	1843	1811
Ukai 6*	2368	2323	2340	2359	2402	2358
Wanakbori 8 TPS*	-	-	2189	2153	2226	2189

Table 16: Actual Station Heat Rate of Existing Stations/Units (kcal/kWh) for TPL-G

Power Station	FY 2017-2018	FY 2018-2019	FY 2019-2020	FY 2020-2021	FY 2021-2022	Average
Sabarmati 'D'	2435	2430	2451	2454	2435	2441
Sabarmati 'E'	2438	2431	2447	2448	2428	2438
Sabarmati 'F'	2445	2407	2433	2427	2395	2421

5.9.8 It is observed that some of the stations have achieved better SHR than the normative SHR approved by the Commission for the third Control Period, while in case of some other Generating Stations; the actual SHR has been higher than the same approved by the Commission. Further, there are some Generating Stations whose actual SHR has been very close to the normative SHR stipulated by the Commission.

a) The paras below provide a brief summary of Unit/Station wise actual SHR achieved by the Generating Stations of GSECL: Ukai TPS (3-5): The Ukai (Unit 1 and 2) were decommissioned in the last control period. The Units 3 to 5 of Ukai Station have also outlived its useful life and have been in operation for around 35 to 40 years. There is no particular trend of SHR during the period from 2017-18 to FY 2021-22. Based on the performance, it is proposed that the normative SHR for

Ukai (3-5) to be 2572 kcal/kWh, which is the average SHR achieved during past five years of operation, i.e., FY 2017-18 to FY 2021-22.

b) Gandhinagar TPS (3-4): The average actual SHR achieved by Gandhinagar (3-4) was 2545 kcal/kWh during the period FY 2017-18 to FY 2021-22. Considering the past performance of the Stations, it suggested that the normative SHR for Gandhinagar (Unit 3-4) for the next Control Period should remain the same at a value of 2545 kcal/kWh which is the average SHR achieved during past five years i.e., from FY 2017-18 to FY 2021-22.

c) Wanakbori (Unit 1-6):There is no particular trend of SHR during the period from 2017-18 to FY 2021-22. Based on the performance, it is proposed that the normative SHR for Wanakbori (Unit 1-6) is to be 2556 kcal/kWh, which is the average SHR achieved during past five years of operation, i.e., FY 2017-18 to FY 2021-22.

d) KLTPS (Unit-3): The Units 1 & 2 were de-commissioned with effect from January 2020. Further, the Unit 3 was commissioned on March 31, 1997, and has completed around 23 years of its useful life. The unit wise availability of KLTPS was not available, however, based on the past year performance, the actual SHR achieved by KLTPS (Units 1-3) was 3231 kcal/kWh during FY 2017-18 to FY 2020-21. The SHR of KLTPS during 2021-22 has been 3254 kcal/kWh which is more than the existing normative SHR of 3231 kcal/kWh. Therefore, it is proposed to keep the SHR of KLTPS-3 at 3231 kcal/kWh. However, based on the actual performance of Unit 3, the Commission may revise the norms at later stage.

e) KLTPS (Unit-4): The average SHR achieved by KLTPS (Unit-4) during the period FY 2017-18 to FY 2021-22 is 3077 kcal/kWh, as against the approved normative SHR of 3000 kcal/kWh. In view of above, it is proposed to specify normative SHR for KLTPS Unit-4 as 3000 kcal/kWh for the next Control Period.

f) Dhuvaran CCPP 2: The average SHR achieved by Dhuvaran CCPP-2 is 2138 kcal/kWh during the period FY 2017-18 to FY 2021-22 against the approved normative SHR of 1950 kcal/kWh applicable for the Control Period. The Dhuvaran (Gas-2) station was commissioned in the year 2007. There is no particular trend of SHR during the period from 2017-18 to FY 2021-22. Based on the performance, it is proposed that the normative SHR for Dhuvaran CCPP 2 is to be 2138 kcal/kWh, which is the average SHR achieved during past five years of operation, i.e., FY 2017-18 to FY 2021-22.

g) PPA governed stations: Ukai Extn. (Unit - 6), Gandhinagar (Unit -5), Wanakbori (Unit – 7 and 8), Sikka Extn. (Unit 3-4), Dhuvaran CCPP – 1, Dhuvaran - CCPP 3, Utran Extension and BLTPS (Unit- 1 and 2) are PPA governed stations wherein, the station heat rate shall be governed based on the terms of the respective PPAs.

5.9.9 The paras below provide a brief summary of Unit/Station wise actual SHR achieved by the Generating Stations of TPL-G:

a) Sabarmati-D: The SHR approved for Sabarmati-D is 2450 kcal/kWh during the period FY 2017-18 to FY 2021-22. However, the average of actual SHR achieved by the said Stations over the past five year is 2441 kcal/kg which is the comparable to existing normative SHR. Thus, in view of above, it is proposed to specify normative SHR of 2440 kcal/kWh for the next Control Period as well.

b) Sabarmati-E: The SHR approved for Sabarmati-E is 2455 kcal/kWh during the period FY 2017-18 to FY 2021-22. However, the average of actual SHR achieved by the said Stations over the past five year is 2438 kcal/kg which is comparable to the existing normative SHR. Thus, in view of above, it is proposed to specify normative SHR of 2438 kcal/kWh for the next Control Period as well.

c) Sabarmati-F: The SHR approved for Sabarmati-F is 2455 kcal/kWh during the period FY 2017-18 to FY 2021-22. However, the average of actual SHR achieved by the said Stations over the past five year is 2421 kcal/kg which is comparable to the existing normative SHR. Thus, in view of above, it is proposed to specify normative SHR of 2420 kcal/kWh for the next Control Period as well.

5.9.10 The proposed norms for SHR for GSECL's and TPL-G Generating Stations are as under:

Table 17: Station Heat Rate norms for GSECL's and TPL Generating Stations (kcal/kWh)

Power Station	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
Ukai (3-5)	2572	2572	2572	2572	2572
Gandhinagar (3-4)	2545	2545	2545	2545	2545
Gandhinagar 5*	2460	2460	2460	2460	2460
Wanakbori 1-6 TPS	2556	2556	2556	2556	2556
Wanakbori 7*	2460	2460	2460	2460	2460
Sikka Extension (3-4)*	2398	2398	2398	2398	2398
KLTPS 3	3231	3231	3231	3231	3231
KLTPS 4	3000	3000	3000	3000	3000
BLTPS*	2623	2623	2623	2623	2623
Dhuvaran CCPP 1*	1950	1950	1950	1950	1950
Dhuvaran CCPP 2	2138	2138	2138	2138	2138
Dhuvaran CCPP 3*	1850	1850	1850	1850	1850
Utran Extension*	1850	1850	1850	1850	1850

Power Station	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
Ukai 6*	2385	2385	2385	2385	2385
Wanakbori 8 TPS*	2248	2248	2248	2248	2248
Sabarmati 'D'	2440	2440	2440	2440	2440
Sabarmati 'E'	2438	2438	2438	2438	2438
Sabarmati 'F'	2420	2420	2420	2420	2420

**PPA Based station*

5.9.11 Further, CERC, in its Explanatory Memorandum to the draft IEGC, 2022 has mentioned that since norms for generating stations under Section 62 are determined under the Tariff Regulations, the appropriate placement of compensation for such projects should be through the Tariff Regulations. Therefore, the norms are now to be dealt as a part of the Tariff Regulations and therefore, appropriate provisions need to be inserted. The Commission proposes that the Generating Company may be compensated for degradation in SHR on account of backing down on case-to-case basis, subjected to prudence check by the Commission.

5.9.12 Further, for new Generating Stations, the GERC MYT Regulations, 2016 provides for computation of Gross Station Heat Rate as 1.045 times of the Design Heat Rate of Station/unit. However, CERC Tariff Regulations, 2019 has revised the norms based on the recommendation of CEA to reflect the current operational efficiencies of the stations by increasing the margin above Design Heat rate to 5.00% from the current level of 4.50%. It is proposed to adopt the approach followed by CERC. Hence, Gross SHR for all Generating Stations commissioned on or after April 01, 2009, shall be 1.05 times of Design Heat rate of Station/unit. Accordingly, for new Generating Units/Stations to be commissioned on or after April 01, 2016, the Station Heat Rate norm is proposed to be in accordance with the norms specified as per CERC Tariff Regulations 2019, as under:

"53.2.3 Gross Station Heat Rate – For new Generating Units or stations achieving COD after the 1.4.2016:

i) For Coal-based and lignite-fired Thermal Generating Stations:

=1.05 X Design Heat Rate (kCal/kWh)

Where the Design Heat Rate of a generating unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR (Maximum Continuous Rating), 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***
SHT/RHT (0C)	*535/535*	*537/537*	*537/565*
Type of BFP	*Electrical Driven*	*Turbine Driven*	*Turbine Driven*
Max Turbine Heat Rate (kCal/kWh)	*1955*	*1950*	*1935*
Min. Boiler Efficiency			
Sub-Bituminous Indian Coal	*0.86*	*0.86*	*0.86*
Bituminous Imported Coal	*0.89*	*0.89*	*0.89*
Max. Design Heat Rate (kCal/kWh)			
Sub-Bituminous Indian Coal	*2273*	*2267*	*2250*
Bituminous Imported Coal	*2197*	*2191*	*2174*

Pressure Rating (Kg/cm2)	***247***	***247***	***270***	***270***
SHT/RHT (0C)	*537/565*	*565/593*	*593/593*	*600/ 600*
Type of BFP	*Turbine Driven*	*Turbine Driven*	*Turbine Driven*	*Turbine Driven*
Max Turbine Heat Rate (kCal/kWh)	*1900*	*1850*	*1810*	*1800*
Min. Boiler Efficiency				
Sub-Bituminous Indian Coal	*0.86*	*0.86*	*0.865*	*0.865*
Bituminous Imported Coal	*0.89*	*0.89*	*0.895*	*0.895*
Max. Design Heat Rate (kCal/kWh)				
Sub-Bituminous Indian Coal	*2222*	*2151*	*2105*	*2081*
Bituminous Imported Coal	*2135*	*2078*	*2034*	*2022*

”

5.10 Secondary Fuel Oil Consumption

5.10.1 As per GERC MYT Regulations, 2016, the Commission provided the normative secondary fuel oil consumption (SFC) for coal-based Generating Stations as 0.50 ml/kWh, lignite-based Generating Stations other than having CFBC technology as 2.00 ml/kWh and for lignite-based Generating Stations having CFBC technology as 1.00 ml/kWh. Further, the Commission has specified the normative SFC for the existing GSECL and TPL-G Generating Stations as shown below:

“53.5 Secondary fuel oil consumption:

…

b) SFC norm for following GSECL stations, shall be as under:

Table 5: SFC for GSECL generating stations under Regulation 53.5 (b) for the Control Period

Stations	FY 2016-17 (ml/kWh)	FY 2017-18 (ml/kWh)	FY 2018-19 (ml/kWh)	FY 2019-20 (ml/kWh)	FY 2020-21 (ml/kWh)
UkaiTPS (Unit 1-5)	1.00	1.00	1.00	1.00	1.00
GandhinagarTPS (Unit 1-4)	1.50	1.50	1.50	1.50	1.50
Wanakbori (Unit 1-6)	1.00	1.00	1.00	1.00	1.00
SikkaTPS	3.00	3.00	3.00	3.00	3.00
Kutch Lignite TPS (Unit 1- 4)	3.00	3.00	3.00	3.00	3.00
Ukai 6	1.00	1.00	1.00	1.00	1.00
Sikka 3 & 4	1.00	1.00	1.00	1.00	1.00

c) SFC norm for following TPL-G station, shall be as under:

Stations	FY 2016-17 (ml/kWh)	FY 2017-18 (ml/kWh)	FY 2018-19 (ml/kWh)	FY 2019-20 (ml/kWh)	FY 2020-21 (ml/kWh)
Sabarmati C	2.00	2.00	2.00	2.00	2.00
Sabarmati 'D', ‘E’, and ‘F’	1.00	1.00	1.00	1.00	1.00

Provided that the Commission may revise the norms for the secondary fuel oil consumption for the above mentioned Generating Stations in case of Renovation & Modernisation undertaken by the Generating Station.”

5.10.2 The table below provides the summary of actual SFC data from FY 2017-18 to FY 2021-22 for GSECL and TPL-G’s Generating Stations as approved by the Commission during the true up of respective years:

Table 18: Actual SFC of Existing Stations/Units (kcal/kWh) for GSECL

Generating Stations	FY 2016-17 (ml/kWh)	FY 2017-18 (ml/kWh)	FY 2018-19 (ml/kWh)	FY 2019-20 (ml/kWh)	FY 2020-21 (ml/kWh)
UkaiTPS (Unit 1-5)	1.00	1.00	1.00	1.00	1.00
GandhinagarTPS (Unit 1-4)	1.50	1.50	1.50	1.50	1.50
Wanakbori (Unit 1-6)	1.00	1.00	1.00	1.00	1.00
SikkaTPS	3.00	3.00	3.00	3.00	3.00
Kutch Lignite TPS (Unit 1- 4)	3.00	3.00	3.00	3.00	3.00
Ukai 6	1.00	1.00	1.00	1.00	1.00

Table 19: Actual SFC of Existing Stations/Units (kcal/kWh) for TPL-G

Generating Stations	FY 2016-17 (ml/kWh)	FY 2017-18 (ml/kWh)	FY 2018-19 (ml/kWh)	FY 2019-20 (ml/kWh)	FY 2020-21 (ml/kWh)

Generating Stations	FY 2016-17 (ml/kWh)	FY 2017-18 (ml/kWh)	FY 2018-19 (ml/kWh)	FY 2019-20 (ml/kWh)	FY 2020-21 (ml/kWh)
Sabarmati C	2.00	2.00	2.00	2.00	2.00
Sabarmati 'D', 'E', and 'F'	1.00	1.00	1.00	1.00	1.00

5.10.3 The table below provide a brief summary of Unit/Station wise actual SFC achieved by the Generating Stations of GSECL and TPL(G) based on the data submitted by the utilities:

Table 20: Unit/Station wise actual SFOC (ml/kWh)

Power Station	FY 2017-2018	FY 2018-2019	FY 2019-2020	FY 2020-2021	FY 2021-2022	2 Years	5 Years
Ukai (3-5)	1.32	1.01	1.32	3.51	8.07	5.79	3.05
Gandhinagar (3-4)	0.97	0.84	2.59	1.23	1.23	1.23	1.37
Gandhinagar 5*	0.37	0.46	0.83	0.69	0.84	0.77	0.64
Wanakbori 1-6 TPS	1.1	0.87	1.51	1.24	2.15	1.70	1.37
Wanakbori 7*	0.32	0.17	0.83	0.58	1.3	0.94	0.64
Sikka Extension (3-4)*	1.27	1.13	1.25	2.08	1.8	1.94	1.51
KLTPS 3					7.55	7.55	7.55
KLTPS 4	4.35	1.63	2.61	4.51	9.39	6.95	4.50
BLTPS*	-	-	5.09	6.24	2.98	4.61	4.77
Ukai 6*	0.31	0.26	0.66	3.26	1.87	2.57	1.27
Wanakbori 8 TPS*	-	-	3.67	0.99	1.42	1.21	2.03

5.10.4 The paras below provide a brief summary of Unit/Station wise actual SFOC achieved by the Generating Stations of GSECL:

a) Ukai (Unit 3-5): The average SFC of Ukai (3-5) was 3.05 ml/kWh during the period FY 2017-18 to FY 20221-22 as compared to normative SFC of 1.00 ml/kWh. The SFC are higher generally due to partial operation on account of backing down and frequent start stop operations. The Commission has already proposed an enabling clause to provide compensation on case-to-case basis to address the impact of partial operation on SFC. In view of above, it is proposed to continue with the existing norms of SFC for the next Control Period.

b) Gandhinagar (Unit 3-4): The average SFC of Gandhinagar (Unit 3-4) was 1.37 ml/kWh during the period FY 2017-18 to FY 2021-22 as compared to normative SFC of 1.50 ml/kWh. As the SFC of Gandhinagar (Unit 3-4) is within the range of the normative SFC as specified in the MYT Order, the Commission proposes to continue with the existing normative SFC of 1.50 ml/kWh for the next Control Period.

c) Wanakbori (Unit 1-6): The average SFC of Wanakbori (Unit 1-6) was 1.37 ml/kWh during the period FY 2017-18 to FY 2021-22 as compared to normative SFC of 1.00 ml/kWh. The average of actual SFC over the past five years was observed to be significantly higher than the existing norms. In view of above, the Commission is of the opinion that the current norm of SFC of 1.00 ml/kWh for the station is in line with the norms specified by CERC and the Commission cannot allow to pass on the inefficiencies of the Generating Stations to be passed on to the consumers. Thus, it is suggested that the existing norms of 1.00 ml/kWh may be retained for next Control Period.

d) KLTPS (Unit 3): The average SFC of KLTPS (Unit-3) was 7.55 ml/kWh during the period FY 2017-18 to FY 2021-22 as compared to normative SFC of 3.00 ml/kWh. The higher SFC for KLTPS is mainly due to forced outages and other issues like non availability of coal mills due to poor lignite quality. However, as already mentioned that the Commission in the draft Regulations has proposed an enabling clause to deal with the partial operation on plant, hence, Commission does not find any merit in giving further relaxation to the station. Also, the Unit 1 & 2 of KLTPS has been decommissioned. Thus, in view of above, it is suggested to continue with the existing norms of 3.00ml/kWh for the next Control Period.

e) KLTPS (Unit-4): The average SFC of KLTPS (Unit-4) was 4.50 ml/kWh during the period FY 2017-18 to FY 2021-22 as compared to normative SFC of 3.00 ml/kWh. The higher SFC for KLTPS is mainly due to forced outages and other issues like non availability of coal mills due to poor lignite quality. However, as already mentioned that the Commission in the draft Regulations has proposed an enabling clause to deal with the partial operation on plant, hence, Commission does not find any merit in giving further relaxation to the station. Also, the Unit 1 & 2 of KLTPS has been decommissioned. Thus, in view of above, it is suggested to continue with the existing norms of 3.00ml/kWh for the next Control Period.

f) PPA governed stations: Ukai –Extn. (Unit - 6), Gandhinagar (Unit -5), Wanakbori (Unit -7), Wanakbori (Unit-8), Sikka Extn. (Unit 3-4), BLTPS are PPA governed stations wherein, the Commission has approved the SFC based on the terms of the respective PPAs. For the next Control Period, the normative SFC for PPA based stations shall be governed by respective terms of PPA.

5.10.5 The paras below provide a brief summary of Unit/Station wise actual SFC achieved by the Generating Stations of TPL-G based on the data submitted by the utilities:

Table 21: Summary of Unit/Station wise actual SFC TPL-G

Power Station	FY 2017-2018	FY 2018-2019	FY 2019-2020	FY 2020-2021	FY 2021-2022	2 Years	5 Years
Sabarmati 'D'	0.54	0.31	0.4	2.07	0.5	1.29	0.76
Sabarmati 'E'	0.18	0.15	0.34	0.22	0.17	0.20	0.21
Sabarmati 'F'	0.37	0.19	0.19	0.6	0.17	0.39	0.30

5. Sabarmati (D, E, and F): The average SFOC of Sabarmati (D, E, and F) was 0.76 ml/kWh, 0.21 ml/kWh and 0.30 ml/kWh respectively during in the period FY 2017-18 to FY 2021-22 as compared to normative SFOC of 1.00 ml/kWh. It is observed that the average of actual SFOC achieved over the past five year is less than 1.00 ml/kWh. The reason for such lower SFOC may be attributed to efficient operation and maintenance undertaken by the station. Based on the actual performance of the plant, the Commission has proposed to revise the normative SFOC to 1.00 ml/kWh which is equivalent to the average of normative SFOC achieved over the past five years.

5.10.6 Therefore, the proposed norms of SFC for GSECL's and TPL-G's Generating Stations are as under:

Table 22: SFC norms for GSECL's and TPL Generating Stations (ml/kWh)

Power Station	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
Ukai (3-5)	1.00	1.00	1.00	1.00	1.00
Gandhinagar (3-4)	1.50	1.50	1.50	1.50	1.50
Gandhinagar 5*	3.50	3.50	3.50	3.50	3.50
Wanakbori 1-6 TPS	1.00	1.00	1.00	1.00	1.00
Wanakbori 7*	3.50	3.50	3.50	3.50	3.50
Sikka Extension (3-4)*	1.00	1.00	1.00	1.00	1.00
KLTPS 3	3.00	3.00	3.00	3.00	3.00
KLTPS 4	3.00	3.00	3.00	3.00	3.00
BLTPS*	1.00	1.00	1.00	1.00	1.00
Ukai 6*	1.00	1.00	1.00	1.00	1.00
Wanakbori 8 TPS*	0.50	0.50	0.50	0.50	0.50
Sabarmati 'D'	1.00	1.00	1.00	1.00	1.00
Sabarmati 'E'	1.00	1.00	1.00	1.00	1.00
Sabarmati 'F'	1.00	1.00	1.00	1.00	1.00

5.10.7 For new Generating Station, the Secondary Fuel Oil Consumption norm is proposed in accordance with the norms specified in CERC Tariff Regulations, 2019 as under:

"53.3.3 SFC for all thermal generating Units/Stations, except those covered under Regulation 53.3.1 and Regulation 53.3.2 shall be as under:

(i) Coal-based generating stations: 0.50 ml/kWh;

(ii) Lignite-Fired generating stations: 1.00 ml/kWh

(iii) For Generating Stations based on Coal Rejects: 2.0 ml/kWh"

5.11 Limestone Consumption

5.11.1 As per Regulation 53.6 of GERC MYT Regulations 2016, the Limestone consumption for Lignite based stations using CFBC Technology is considered as 0.05 kg/ kWh. Further, CERC in its Tariff Regulations, 2019 has also specified the same. Therefore, the Commission proposes to continue with the same for the fourth MYT Control Period in accordance with the CERC Tariff Regulations, 2019.

5.12 Auxiliary Energy Consumption

5.12.1 The Auxiliary Energy Consumption (AEC) is the energy consumed by various auxiliaries of Generating Station such as equipment used for operating plant and machinery, including switchyard of the Generating Station and the transformer losses within the Generating Station, fans, motors etc. The Commission in the GERC MYT Regulations, 2016 has specified separate auxiliary energy consumption norms for new and existing coal/lignite based Generating Stations, whereas for gas turbine/combined cycle Generating Stations, common norms of auxiliary energy consumption were specified.

Auxiliary Energy Consumption for existing Generating Stations:

5.12.2 The table below shows the comparison of actual AEC vis-à-vis normative AEC for existing Generating Station of GSECL and TPL-G based on the data submitted by the utilities:

Table 23: Comparison of Normative vis-à-vis Actual Auxiliary Energy Consumption (%)

Power Station	FY 2017-2018	FY 2018-2019	FY 2019-2020	FY 2020-2021	FY 2021-2022	2 Years	5 Years
Ukai (3-5)	9.67%	9.55%	9.90%	10.30%	10.24%	10.27%	9.93%
Gandhinagar (3-4)	10.59%	10.56%	12.75%	11.27%	10.32%	10.80%	11.10%
Gandhinagar 5*	9.82%	9.64%	10.71%	11.05%	10.41%	10.73%	10.33%
Wanakbori 1-6 TPS	9.09%	9.11%	9.90%	10.24%	9.94%	10.09%	9.66%
Wanakbori 7*	9.07%	9.17%	9.92%	10.06%	10.08%	10.07%	9.66%
Sikka Extension (3-4)*	9.65%	9.49%	9.47%	9.99%	10.53%	10.26%	9.83%
KLTPS 3					13.53%	13.53%	13.53%
KLTPS 4	21.80%	22.74%	21.96%	23.39%	39.36%	31.38%	25.85%
BLTPS*			23.97%	22.78%	19.04%	20.91%	21.93%
Dhuvaran CCPP 1*	7.26%	7.35%	7.35%	5.53%	10.60%	8.07%	7.62%
Dhuvaran CCPP 2	5.33%	6.85%	9.81%	5.54%	13.82%	9.68%	8.27%
Dhuvaran CCPP 3*	26.02%	6.04%	4.36%	2.88%	7.67%	5.28%	9.39%
Utran Extension*	6.04%	4.24%	3.96%	2.42%	5.70%	4.06%	4.47%

Power Station	**FY 2017-2018**	**FY 2018-2019**	**FY 2019-2020**	**FY 2020-2021**	**FY 2021-2022**	**2 Years**	**5 Years**
Ukai 6*	5.94%	6.05%	6.42%	6.68%	7.23%	6.96%	6.46%
Wanakbori 8 TPS*			8.81%	5.53%	5.22%	5.38%	6.52%
Ukai Hydro	1.04%	1.19%	0.73%	0.75%	0.77%	0.76%	0.90%
Kadana Hydro	0.87%	0.76%	0.65%	0.67%	0.76%	0.72%	0.74%
Sabarmati 'D'	9.05%	8.63%	9.08%	10.63%	9.28%	9.96%	9.33%
Sabarmati 'E'	8.40%	8.16%	8.65%	9.51%	8.55%	9.03%	8.65%
Sabarmati 'F'	8.92%	8.62%	8.89%	9.55%	8.82%	9.19%	8.96%

**PPA Based*

5.12.3 From the table above, with regard to GSECL's Generating Stations, it was observed that the actual auxiliary consumption achieved by all coal/lignite/gas based thermal generating stations not governed by the PPAs plants is higher than normative value specified by the Commission. The reason for such a higher auxiliary consumption as stated by Utility, is mainly on account of partial operation of stations due to backing downs. Further to address such issue on account of backing down, the Commission in the draft GERC MYT Regulations, 2023 has proposed an enabling clause wherein it has proposed that the compensation may be provided to Generation Stations due to backing down on case-to-case basis, subjected to prudence check. Thus, it is proposed that no relaxation should be given to any generating stations for reasons attributed to partial operation due to backing down or reserve shut down.

5.12.4 The Commission has analysed the station wise AEC based on the historical performance of the stations. The paras below provide the summary of analysis of AEC of GSECL's Generating Stations:

a) Ukai (Unit 3-5): The average AEC of Ukai (Unit 3-5) for the period FY 2017-18 to FY 2021-22 period was 9.93%, which is similar to the normative AEC of 9.00% applicable during the above period. Therefore, the Commission has proposed to continue with existing norm of 9.00% for normative AEC for the next Control Period.

b) Gandhinagar (Unit 3-4): The average AEC of Gandhinagar (Unit 3-4)) for the period FY 2017-18 until FY 2021-22 was 11.10%, which is significantly higher than the normative AEC of 9.00% applicable during the above period. With the view to impose better efficiency, the current norm of 9.00% auxiliary energy consumption may be continued for the Gandhinagar (3-4) TPS for the next Control Period.

c) Wanakbori (Unit 1-6): The AEC of Wanakbori (Unit 1-6) for the period FY 2017-18 to FY 2021-22 was 9.66%, which is comparable to the normative AEC of 9.00%

applicable during the above period. Therefore, the Commission has proposed to continue with existing the normative AEC of 9.00% for next Control Period.

d) KLTPS (Unit-3): The actual AEC of KLTPS (Unit 3) for the FY 2021-22 was 13.53%, which is higher than the normative AEC of 12.00% for the FY 2021-22. Further, the Unit 1 & 2 of KLTPS is now decommissioned. In view of the above, it is proposed that no further relaxation should be given to Unit 3 of KLTPS, as the current norm of 12.00% is already on the higher side. Accordingly, the existing norm is proposed to continue.

e) KLTPS (Unit-4): The average AEC achieved by KLTPS (Unit-4) for the period FY 2017-18 to FY 2021-22 was 25.85%, which is more than twice the normative AEC of 12.00% applicable during the above period. The existing norms of AEC for KLTPS Unit 4 is already higher and the same may not be relaxed further. Thus, it is suggested that the normative auxiliary energy consumption of 12% for the KLTPS-4 specified in the GERC MYT Regulations, 2016 may be continued in the next Control Period.

f) Dhuvaran CCPP-2: The average auxiliary energy consumption (AEC) of Dhuvaran CCPP-2 for the period FY 2017-18 to FY 2021-22 was 8.27%, which is much higher than the normative AEC of 3.00% applicable during the above period. It is observed that the actual AEC achieved during FY 2017-18 to FY 2021-22 is consistently higher than the normative AEC approved by the Commission mainly on account of backing down. As the Commission has proposed to provide compensation on AEC for backing down in these draft Regulations, the Commission has proposed the continue with the existing norms of normative AEC for the next control period.

g) PPA governed stations: Ukai Extn. (Unit - 6), Gandhinagar (Unit -5), Wanakbori (Unit -7), Wanakbori (Unit -8), Sikka Extn. (Unit 3-4), Dhuvaran (1 & 3) and BLTPS are PPA governed stations wherein, the Commission has approved the AEC based on the terms of the respective PPAs. The normative parameters of above Units for next Control Period shall be governed by the respective terms of PPA.

5.12.5 Regarding TPL-G's Generating Stations, it was observed that the all Generating Stations of TPL-G are able to achieve norms with marginal deviations. The actual performance of stations has improved over the past period. Therefore, considering the consistent improvement trend, the Commission has proposed a marginal improvement in normative AEC for stations 'D' & 'F' of TPL-G to 9.00% and for station 'E' to 8.50% for the next Control Period.

5.12.6 Therefore, the proposed norms of AEC for GSECL's and TPL-G's Generating Stations are as under:

Table 24: Auxiliary Energy Consumption (%) for coal/lignite/gas based Generating Stations of GSECL and TPL-G for the Control Period

Power Station	**FY 2024-25**	**FY 2025-26**	**FY 2026-27**	**FY 2027-28**	**FY 2028-29**
Ukai (3-5)	9.00%	9.00%	9.00%	9.00%	9.00%
Gandhinagar (3-4)	9.00%	9.00%	9.00%	9.00%	9.00%
Gandhinagar 5*	9.50%	9.50%	9.50%	9.50%	9.50%
Wanakbori 1-6 TPS	9.00%	9.00%	9.00%	9.00%	9.00%
Wanakbori 7*	9.50%	9.50%	9.50%	9.50%	9.50%
Sikka Extension (3-4)*	9.00%	9.00%	9.00%	9.00%	9.00%
KLTPS 3	12.00%	12.00%	12.00%	12.00%	12.00%
KLTPS 4	12.00%	12.00%	12.00%	12.00%	12.00%
BLTPS*	11.00%	11.00%	11.00%	11.00%	11.00%
Dhuvaran CCPP 1*	4.00%	4.00%	4.00%	4.00%	4.00%
Dhuvaran CCPP 2	3.00%	3.00%	3.00%	3.00%	3.00%
Dhuvaran CCPP 3*	3.00%	3.00%	3.00%	3.00%	3.00%
Utran Extension*	3.00%	3.00%	3.00%	3.00%	3.00%
Ukai 6*	6.00%	6.00%	6.00%	6.00%	6.00%
Wanakbori 8 TPS*	5.25%	5.25%	5.25%	5.25%	5.25%
Ukai Hydro	0.60%	0.60%	0.60%	0.60%	0.60%
Kadana Hydro	1.00%	1.00%	1.00%	1.00%	1.00%
Sabarmati 'D'	9.00%	9.00%	9.00%	9.00%	9.00%
Sabarmati 'E'	8.50%	8.50%	8.50%	8.50%	8.50%
Sabarmati 'F'	9.00%	9.00%	9.00%	9.00%	9.00%

**PPA Based Station*

5.12.7 For new Generating Unit/Stations to be commissioned after the implementation of the GERC MYT Regulations, 2023, the auxiliary consumption norm is proposed to be in line with the norms specified in CERC Tariff Regulations, 2019 for various technologies and Unit sizes as under:

“53.5.3 New Coal-based Generating Stations:

Table 8: Auxiliary Energy Consumption (%) for new coal-based generating station

Auxiliary Energy Consumption	***With Natural Draft cooling tower or without cooling tower***
(i) 200 MW series	*8.50%*
(ii) 250/330/350/500 MW & above	
Steam driven boiler feed pumps	*5.75%*

Auxiliary Energy Consumption	***With Natural Draft cooling tower or without cooling tower***
Electrically driven boiler feed pumps	*8.00%*

Provided that for thermal generating stations with induced draft cooling towers and where tube type coal mill is used, the norms shall be further increased by 0.5% and 0.8% respectively.

Provided further that Additional Auxiliary Energy Consumption as follows shall be allowed for plants with Dry Cooling Systems

Table 9: Additional Auxiliary Energy Consumption for thermal generating stations with dry cooling systems

S. No.	***Type of Dry Cooling System***	***(% of gross generation)***
(i)	*Direct cooling air cooled condensers with mechanical draft fans*	*1.0%*
(ii)	*Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower*	*0.5%*

”

5.12.8 In regards to the Auxiliary Consumption for Flue Gas Desulphurization (FGD), the Commission observed that CERC has issued Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (First Amendment) Regulations, 2020 on April 1, 2020; wherein it has provided AEC on account of emission control system of thermal Generating Stations as under:

“53.5.4 Auxiliary Energy Consumption (AUXe) on account of emission control system of thermal generating stations:

Table10: Auxiliary Energy Consumption (AUXe) on account of emission control system of thermal generating stations

Name of Technology	**AUXen (as % of gross generation)**
(1) For reduction of emission of Sulphur dioxide:	
a) Wet Limestone based FGD system(without Gas to Gas heater)	1.0%
b) Lime Spray Dryer or Semi dry FGD System	1.0%
Dry Sorbent Injection System (using Sodium bicarbonate)	NIL
For CFBC Power plant (furnace injection)	NIL
Sea Water based FGD system (without Gas to Gas heater)	0.7%
(2) For reduction of emission of nitrogen:	

Name of Technology	AUXen (as % of gross generation)
a) Selective Non-Catalytic Reduction system	NIL
b) Selective Catalytic Reduction system	0.2%

Provided that where the technology is installed with Gas to Gas heater, auxiliary energy consumption specified as above shall be increased by 0.3% of gross generation.”

“53.6 Norms for consumption of reagent:

53.6.1 The normative consumption of specific reagent for various technologies for reduction of emission of sulphur dioxide shall be as below:

(a) For Wet Limestone based Flue Gas De-sulphurisation (FGD) system: *The specific limestone consumption (g/kWh) shall be worked out by following formula:*

[0.85 x K x SHR x S]/[CVPF x LP]

Where,

S = Sulphur content in percentage,

LP = Limestone Purity in percentage,

SHR= Gross station heat rate, in kCal per kWh;

CVPF= (a) Weighted Average Gross calorific value of coal as received, in kcal per kg for coal-based stations less actual stacking losses in calorific value of coal on account of variation during storage at generating station;

Provided that the actual stacking losses shall be subjected to the maximum stacking loss of 85 kcal/kg for pithead stations and 120 kcal/kg for non-pithead stations.

(b) Weighted Average Gross calorific value of primary fuel as received, in kcal per kg, per litre or per standard cubic meter, as applicable for lignite-based stations.

(c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio.

Provided that value of K shall be equivalent to (35.2 x Design SO2 Removal Efficiency/96%) for units to comply with SO2 emission norm of 100/200 mg/Nm3 or (26.8xDesign SO2 Removal Efficiency/73%) for units to comply with SO2 emission norm of 600 mg/Nm3;

Provided further that the limestone purity shall not be less than 85%.

(b) For Lime Spray Dryer or Semi-dry Flue Gas Desulphurisation (FGD) system: *The specific lime consumption shall be worked out based on minimum purity of lime (PL) as at 90% or more by applying formula [0.90x6 /PL(%)] gm/kWh;*

(c) For Dry Sorbent Injection System (using sodium bicarbonate): *The specific consumption of sodium bicarbonate shall be 12 gm per kWh at 100% purity.*

(d) For CFBC Technology (furnace injection) based generating station: *The specific limestone consumption for CFBC based generating station (furnace injection) at 85% purity limestone (kg/kWh) shall be computed with the following formula:*

$$[\ 62.9 \times S \times SHR / CVPF] \times [0.85/\ LP]$$

Where

S= Sulphur content in percentage,

LP = Limestone Purity in percentage,

SHR= Gross station heat rate, in kCal per kWh,

CVPF = (a) Weighted Average Gross calorific value of coal as received, in kcal per kg for coal based stations less actual stacking losses in calorific value of coal on account of variation during storage at generating station;

Provided that the actual stacking losses shall be subjected to the maximum stacking loss of 85 kcal/kg for pithead stations and 120 kcal/kg for non-pithead stations;

(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite based stations;

e. For Sea Water based Flue Gas Desulphurisation (FGD) system: *The reagent used is sea water, therefore there is no requirement for any normative formulae for consumption of reagent. The normative consumption of specific reagent for various technologies for reduction of emission of oxide of nitrogen shall be as below:*

(a) For Selective Non-Catalytic Reduction (SNCR) System: *The specific urea Consumption of SNCR system shall be 1.2 gm per kWh at 100% purity of urea.*

(b) For Selective Catalytic Reduction (SCR) System: *The specific ammonia consumption of SCR system shall be 0.6 gm per kWh at 100% purity of ammonia."*

5.12.9 For new Gas Turbine /Combined Cycle Generating Stations, it is proposed to consider the norm for Auxiliary Consumption in line with CERC Tariff Regulations, 2019, as under:

"Gas Turbine/Combined Cycle generating stations:

New Generating Stations

(i) Combined cycle: 2.75% .

(ii) Open cycle: 1.0%."

5.13 Computation and payment of Annual Energy Charges for Thermal Generating Stations

5.13.1 In regards to the computation of rate of Energy Charges, the existing GERC MYT Regulations, 2016 specifies the formula for coal-based & lignite-fired and Gas & Liquid fuel based Generating Stations as shown below:

a) For coal based and lignite fired stations

ECR = {(GHR – SFC x CVSF) x LPPF / CVPF+SFC x LPSFi + LC x LPL x 100 / (100 – AUX)

b) For gas and liquid fuel-based stations

ECR = GHR x LPPF x 100 / {CVPF x (100 – AUX)}

5.13.2 For the next Control Period, it is proposed to continue with the existing formula. However, some modifications in relation to calculation of Gross Calorific Value (GCV) & ECS related changes has been proposed, which has been discussed in ensuing paras.

5.13.3 As per the formula, the Energy charge is inversely proportional to GCV. A lower GCV would thus lead to a higher tariff. Energy Charge constituting about 60-70% of the total cost of generation tariff has major impact on cost to end consumers. Therefore, GCV being used for the computation of energy input becomes extremely important as any increase/reduction in GCV decreases/increases the admissible coal consumption affecting the cost of power. In order to balance the interest of both the Generating Companies as well as the distribution companies (and ultimately the end consumers), the measurement of GCV of coal used needs to be as accurate as the true representative of the coal consumption is required.

5.13.4 As per the existing GERC MYT Regulations 2016, the "GCV As fired" basis is considered for the Energy Charge Rate (ECR) computation. However, it is to be noted that CERC in its Tariff Regulations, 2014 shifted to "GCV As received" basis from "GCV As fired" basis as per the advice of Central Electricity Authority (CEA), for the purpose of computation of energy charges. Further, CERC in its Tariff Regulations, 2019 has continued with the measurement of GCV on ‘as received basis’ and has also specified that aforementioned measurement is required to be implemented in all coal based thermal Generating Stations effectively. The Commission in line with the CERC approach has proposed to shift from existing “GCV As fired” basis to “GCV As received” basis for energy charge computation.

5.13.5 Further, Central Electricity Authority has recommended for allowing a margin for loss of GCV between “GCV As received” basis at Generation Station (wagon top) to “GCV As Fired” basis. The recommended GCV loss figures in case of pit head Generating Stations is 85-100 Kcal/kg and in case of non-pit head generating stations of 105-120 kcal/kg. Accordingly, the CERC in its Tariff Regulations, 2019 has specified stacking loss of 85 kcal/kg on account of variation during storage at generating station for calculation of energy charge. However, as per the GERC MYT Regulations, 2016, GCV is considered as fired basis thus the losses in GCV of coal due to inefficient handling of Coal is allowed to pass on to the beneficiaries. In order to promote efficient handling of Coal, the Commission in line with CERC and also as per recommendation of CEA, has proposed to consider “GCV as received basis” approach and proposes to allow maximum stacking loss of 85 kcal/kg for pit head Generating Stations and maximum stacking loss of 120 kcal/kg for non-pit head Generating Stations.

5.13.6 Also, in line with CERC approach, a third-party sampling is to be adopted by the Generating Companies at the loading end of mine and unloading end of the Generating Station in order to have more transparency in the measurement of GCV

5.13.7 Accordingly, the “GCV As Received basis”, post adjustment of stacking loss, is proposed to be considered for computation of Energy Charges.

5.13.8 For Coal and Lignite based thermal Generating Station, the Commission has accommodated calculation for reagent consumption for plant that has introduced ECS.

5.13.9 The proposed computation of ECR is shown below:

“60.5. Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis shall be determined to three decimal places in accordance with the following formulae :

(a) For coal based and lignite fired stations

$$ECR = \{(GHR - SFC \times CVSF) \times LPPF / CVPF + SFC \times LPSFi + LC \times LPL + SRC \times LPR\} \times 100 / (100 - AUX_n - AUX_{en})$$

(b) For gas and liquid fuel based stations

$$ECR = GHR \times LPPF \times 100 / \{CVPF \times (100 - AUX)\}$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

CVPF= (a) Weighted Average Gross calorific value of coal as received, in kcal per kg for coal-based stations less actual stacking losses in calorific value of coal on account of variation during storage at generating station;

Provided that the actual stacking losses shall subject to the maximum stacking loss of 85 kcal/kg for pithead stations and 120 kcal/kg for non-pithead stations.

(b) Weighted Average Gross calorific value of primary fuel as received, in kcal per kg, per litre or per standard cubic meter, as applicable for lignite, gas and liquid fuel based stations.

(c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio.

CVSF= Calorific value of secondary fuel, in kcal per ml.

ECR = Energy charge rate, in Rupees per kWh sent out.

GHR = Gross station heat rate, in kcal per kWh.

LC = Normative limestone consumption in kg per kWh.

LPL = Weighted average landed price of limestone in Rupees per kg.

LPPF =Weighted average landed price of primary fuel, in Rupees per kg, per litre or per standard cubic metre, as applicable, during the month. (In case of blending of fuel from different sources, the weighted average landed price of primary fuel shall be arrived in proportion to blending ratio)

SFC = Normative Specific fuel oil consumption, in ml per kWh.

LPSFi=Weighted Average Landed Price of Secondary Fuel in Rs./ml during the month

SRC = Specific reagent consumption on account of revised emission standards (in g/kWh);

LPR = Weighted average landed price of reagent for Emission Control System (in Rs/kg);

AUXen = Normative Auxiliary Energy Consumption of Emission Control System as % of gross generation;

> *Provided that energy charge rate for a gas/liquid fuel based station shall be adjusted for open cycle operation based on certification of Member Secretary of respective Regional Power Committee for the open cycle operation during the month."*

5.13.10 Further, the Commission has proposed to include the following provisions for providing clarification on consideration of fuel price in accordance with the CERC Tariff Regulations, 2019.

> *"Provided that procurement of fuel at a price other than Government notified prices may be considered, if it is based on competitive bidding through transparent process."*

5.13.11 Also, as proposed earlier that GCV of coal is required to be certified by the third party agency, to ensure the accounting of proper quality of coal, any cost related to such certification process will be required to be borne by the beneficiaries and hence, such cost will be allowed as a pass through under O&M cost. The Commission has proposed to include the following provisions for providing clarification on third party sampling for determination of GCV of coal in accordance with the CERC Tariff Regulations, 2019.

> *"Provided also that in case of coal-fired or lignite based thermal generating station, the Gross Calorific Value shall be measured by third party sampling and the expenses towards the third party sampling facility shall be reimbursed by the beneficiaries."*

5.13.12 The GERC MYT Regulations, 2016 does not specify any conditions regarding the consideration of demurrage charges. The Generating plants use wagons of Indian Railways to transport coal from the coal mines (in case of domestic coal) or from the ports (in case of imported coal) to the plants. Once these loaded railway wagons have reached the power plant, they need to be unloaded and released within a stipulated time frame. If there is any delay beyond the stipulated time, the power plant has to pay a penalty cost, known as demurrage cost to the Railway. The unloading of the coal needs to be carried out by the generating company with proper planning so as to avoid any delay. As these charges are levied on the Generating company due to its inefficiency in handling of the fuel, the beneficiary must not be burdened with such charges. Therefore, the Commission in the draft GERC MYT Regulations, 2023 has proposed to disallow the demurrage charges and the following proviso is included in the Regulations.

> *"Provided that, no demurrage charge of railway rakes shall generally be allowed. However, for any demurrage charge cause of which is not attributable to generating company may be allowed subject to prudence check by the Commission. Generating company has to ensure that, it has taken sufficient measures to avoid the occurrence of any demurrage."*

5.14 Transit and Handling Loss

5.14.1 Transit and Handling losses refer to the percentage loss in quantity of coal or lignite during transportation. The losses occur due to weight reduction on account of moisture evaporation, improper stacking of coal, theft, leakages, pilferages etc. and the losses are higher in non-pit head Generating Stations as compared to that in pit head stations. Accordingly, Regulation 53.8 of the GERC MYT 2016, allows transit and handling loss for a Pit head Generating Stations as 0.20% and for non-pit head Generating Station as 0.80%.

5.14.2 The following table shows the past performance of the Thermal Generating Stations of GSECL in the context of transit and handling losses:

Table 25: Table Comparison of Actual and Normative Transit and Handling Loss

Power Station	Normative	FY 2017-2018	FY 2018-2019	FY 2019-2020	FY 2020-2021	FY 2021-2022	Average 2 Years	Average 5 Years
Ukai (3-5)	0.80%	0.17%	0.36%	0.39%	0.32%	0.32%	0.32%	0.31%
Gandhinagar (3-4)	0.80%	0.22%	0.32%	0.10%	0.30%	0.28%	0.29%	0.24%
Gandhinagar 5*	0.80%	0.22%	0.32%	0.10%	0.30%	0.28%	0.29%	0.24%
Wanakbori 1-6 TPS	0.80%	0.16%	0.41%	0.35%	0.34%	0.78%	0.56%	0.41%
Wanakbori 7*	0.80%	0.16%	0.41%	0.35%	0.34%	0.78%	0.56%	0.41%
Sikka Extension (3-4)*	0.80%	0.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%
KLTPS 3	0.80%					0.20%	0.20%	0.20%
KLTPS 4	0.80%	0.20%	0.18%	0.20%	0.20%	0.20%	0.20%	0.20%
BLTPS*	0.80%			0.24%	0.00%	0.20%	0.10%	0.15%
Ukai 6*	0.80%	0.17%	0.36%	0.39%	0.32%	0.32%	0.32%	0.31%
Wanakbori 8 TPS*	0.80%			0.35%	0.34%	0.34%	0.34%	0.34%
TPL-G	0.80%	0.77%	0.92%	0.76%	1.25%	1.96%	1.61%	1.13%

5.14.3 From the table above, it is evident that the actual Transit and Handling losses for all Generating Stations of GSECL not governed by the PPAs and TPL-G are closer to the norms specified in the Regulations.

5.14.4 The Commission has proposed to continue with the existing norms for Transit and handling losses in line with the approach adopted by the CERC Tariff Regulations, 2019.

5.14.5 With respect to imported coal, the CERC Tariff Regulations, 2019 has specified normative transit and handling losses of 0.20% for imported coal. Since there may be some loss of coal in transportation and handling, it is proposed that the normative transit and handling losses of 0.20% may be specified for imported coal, for the next

Control Period in line with the CERC Tariff Regulations, 2019. Further, it may also be specified that the transit loss shall not be applicable if coal is procured on delivery basis.

5.14.6 The Commission has proposed no changes in the said conditions in the draft GERC MYT Regulations, 2023.

5.15 Operation and maintenance expenses for thermal Generating Station

5.15.1 As per the existing provisions of the GERC MYT Regulations, 2016, O&M expenses norms have been specified in terms of Rs. Lakh per MW for new Generating Stations. Whereas for existing Generating Stations, the O&M expenses was specified to be arrived based on an escalation rate of 5.72% over the past approved O&M expenses.

5.15.2 Further, the CERC in its Tariff Regulations, 2019 has specified the common norm for all the existing and new plants except for few very old plants. It is one of the objectives of the MYT framework to move from the methodology of specifying the principles to specifying norms for performance parameters and controllable factors. The Commission is also of the same view, that O&M norms should be same across Generating Stations based on their Unit size or Technology, etc., in line with the CERC approach. However, based on the analysis of past data, it was observed that specifying the norm of O&M expenses may benefit some Generating Stations to a very large extent and significantly impact recovery of O&M expenses of other Generating Stations. As most of the existing Generating Stations are old Stations it would be difficult to specify the norms for such Stations. In view of this, it is proposed to continue with the existing approach for specifying principle rather than norms for existing Generating Stations/units to derive O&M expenses. In case of new Generating Stations, the Commission has specified the norms based on CERC approach.

O&M expenses for Existing Generating Stations:

5.15.3 O&M expenses comprises of R&M expenses, Employee expenses and A&G expenses, which constitute a significant part of the ARR. As mentioned earlier, the present approach of determining O&M expenses is based on the fixed escalation rate of 5.72% only. Such fixed escalation does not capture the real inflation over the years. It also fails to recognise the increase in asset base over the year. Thus, it's essential to address the issue of escalation of O&M expenses due to increased scale of operations and real inflation, which is beyond the control of the Generating Stations.

5.15.4 It has been observed that the CERC and many prominent SERCs have been using Wholesale Price Index (WPI) and Consumer Price Index (CPI) indexation approach for determining escalation rate for O&M expenses. The Commission in the draft GERC

MYT Regulations, 2023 has proposed to adopt the escalation mechanism linked with WPI and CPI index, as it is the transparent way to ascertain the percentage increase in O&M expenses and also takes care of the inflation over the year.

5.15.5 Accordingly, the Commission in the draft GERC Regulations, 2023 has proposed that the O&M expenses comprising of Employee, A&G and R&M expenses; shall be derived on the basis of an inflation factor, which in turn is to be derived based on WPI and CPI index. Further, for arriving at inflation factor, the values for WPI of existing series {Base Year: 2011-12 Series}, is to be considered as per the Office of the Economic Advisor, Ministry of Commerce and Industry, Government of India and CPI-IW (Industrial Worker) {Base Year: 2001=100} as per the Labour Bureau, Government of India. The Commission has proposed that based on the monthly WPI and CPI data as per above sources, yearly inflation factor is to be derived which shall be considered for computation of inflation factor on the basis of respective weightages assigned to WPI and CPI. Further, the Commission has proposed to consider the average data of past 10 years such that any abnormal variation get factored in averaging.

5.15.6 With respect to the R&M expenses, it has been observed that the R&M expenses generally increases with the vintage of plant. Further, R&M activities are usually undertaken for the maintenance of the Fixed Assets, therefore, the Commission proposes to link R&M expenses with the variation in assets base. Accordingly, in addition to the inflation factor to be derived as mentioned above, it is also proposed to have linkage between R&M expenses and Opening Gross Fixed Asset by a constant factor 'K' to have true reflection of R&M expenses. The value of 'K' will be determined by the Commission in the MYT Order which shall be based on ratio of past period average of actual R&M expenses and Opening Gross Fixed Asset. However, the Generating Company may propose their K factor with sufficient reasoning at the time of filing of their MYT Tariff Petition.

5.15.7 In regard to the determination of the weightages to be assigned to WPI and CPI index for calculation of inflation factor, it has been observed that generally the employee related expenses are linked to CPI for Industrial Workers. Whereas, for nonemployee related expenses, i.e., A&G and R&M; overall WPI is a better indicator. Accordingly, based on the data submitted by the utilities, the Commission has analysed the actual O&M expenses incurred by Generating Stations over the past years from FY 2012-13 to FY 2021-22 and has worked out the ratios, viz., employee expenses to the total O&M expenses and A&G and R&M expenses to the total O&M expenses. The average ratio of employee expenses to the total O&M expenses across the aforesaid period has been considered as CPI weightage and the average ratio of A&G and R&M expenses to the total O&M expenses has been considered as a weightage of WPI.

The table below shows the employee expenses as a percentage of total actual O&M expenses for coal based Generating Stations of GSECL and TPL:

Table 26: Employee expenses as percentage of O&M expenses for coal-based Generating Stations

Coal Based thermal Generating station	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	Average (10 Years)
GSECL	57.39%	66.71%	66.68%	65.57%	63.65%	76.76%	55.88%	52.80%	56.94%	50.87%	61.32%
TPL-G	46.58%	42.14%	45.75%	44.61%	43.03%	45.02%	46.56%	42.83%	43.21%	39.27%	43.90%

**PPA Based Stations*

5.15.8 From the above table, it can be observed that the average of employee expenses as a percentage of O&M expenses for GSECL's existing coal based Generating Station ranges from 50.87% to 76.76%. For determination of the weightage of the CPI, the Commission has considered the percentage of average actual employee expenses as percentage of the total O&M expenses of the GSECL's generations stations for the period FY 2012-13 to FY 2021-22 which is worked out as 61.32%. Therefore, an absolute 60% is considered for weightage of CPI. Accordingly, the balance, i.e., 40% (100%-60%) has been assigned to WPI. Hence, it is proposed to consider the weightage to CPI:WPI as 60%:40% for GSECL's coal-based Generating Stations. Similarly, for TPL's Generating Stations, CPI:WPI has been proposed as 40%:60%.

5.15.9 For lignite-based Generating Stations, the Commission has worked out the ratio of employee expenses as a percentage of total actual O&M expenses as shown in the table below:

Table 27: Employee expenses as percentage of O&M expenses for lignite-based Generating Stations

Name of the Plant	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	Average (10 Years)
KLTPS (3-4)	50.86%	57.37%	54.64%	51.15%	56.83%	66.80%	43.21%	43.83%	49.50%	46.69%	52.09%

5.15.10 Based on above, the CPI:WPI weightage for lignite-based Generating Station has been determined at 50%:50%.

5.15.11 Similarly, the Commission has analysed the historical O&M expenses of gas-based Generating Stations to assess the CPI:WPI weightage, as shown in the below table:

Table 28: Employee expenses as percentage of O&M expenses for gas-based Generating Stations

Name of the Plant	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	Average (10 Years)
Gas Based Generating Station	21.74%	29.74%	53.11%	38.61%	36.34%	63.50%	52.42%	41.33%	23.84%	44.60%	40.52%

**PPA Based Stations*

5.15.12 Based on above, the CPI:WPI weightage for gas-based Generating Station has been determined at 40%:60%.

5.15.13 Accordingly, the Commission has proposed the following weightage for calculation of Escalation index based on WPI and CPI:

- For Coal based Generating Stations of GSECL, the WE_{CPI}:WE_{WPI} is to be considered as 60%:40%.
- For Coal based Generating Stations of TPL, the WE_{CPI}:WE_{WPI} is to be considered as 40:60.
- For Lignite based generating stations, the WE_{CPI}:WE_{WPI} is to be considered as 50%:50%.
- For Gas based generating stations, the WE_{CPI}:WE_{WPI} is to be considered as 40%:60%.

5.15.14 The paras below provide the proposed methodology to calculate O&M expenses:

a) The average of actual audited Operation and Maintenance expenses (excluding water charges, Provisions and abnormal expenses etc.) for the past 10 Years ending March 31, 2022 is considered. The average of all three components of O&M expenses; Employee expenses, R&M expenses and A&G expenses is to be calculated individually.

b) The average of such O&M expenses as computed above shall be considered as O&M expenses for the Year ended March 31, 2018 and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, to arrive at the Operation and Maintenance expenses for the base year ending March 31, 2023.

c) Provided further that the escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on the monthly Wholesale Price Index of the respective financial year as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, Government of India.

d) The O&M expenses for the first year and subsequent years of the Control Period shall be determined based on the formula specified in the draft Regulations, as reproduced below:

i. $R\&M_n = K * GFA * (1+\text{Index } Esc_n)$

ii. $EMP_n + A\&G_n = (EMP_{n-1} + A\&G_{n-1}) * (1+\text{Index } Esc_n)$

e) However, for the first year of the Control Period, EMP_{n-1} and $A\&G_{n-1}$ shall mean Employee and A&G expenses of the year after the base year (FY 2022-23) i.e. FY 2023-24, as derived using the escalation rate for FY 2023-24 as mentioned below. Thereafter, from second year of the Control Period, EMP_{n-1} and $A\&G_{n-1}$ shall mean Employee and A&G expenses of the immediately preceding year.

f) For the purpose of estimation of O&M expenses for the MYT Control Period, the same inflation factor as determined for FY 2023-24 shall be used for all years of the Control Period. However, at the time of truing-up of any particular year of the Control Period, the Commission shall calculate revised normative O&M expenses on the basis of actual inflation factor, which is to be derived based on the moving average ofactual values/yearly inflation of WPI and CPI of the respective past ten financial years (including the year of Truing up).

5.15.15 The Commission also proposes to include the relevant clauses towards Wage Revision. These expenses shall be allowed on actual basis based on documentary evidence and justification of Generating Company subject to the prudence check at the time of truing up. The Commission shall not allow any wage revision on the basis of provisioning and shall only allow actual expenses at the time of Truing-up.

5.15.16 Therefore, the Commission proposes the following proviso in relation to determination of O&M expenses for existing thermal station:

"54.1 Existing Generating Stations that achieved CoD before April 01, 2024:

54.1.1 The Operation and Maintenance expenses excluding water charges and including insurance shall be derived on the basis of the average of the actual audited Operation and Maintenance expenses for the past ten Years ending

March 31, 2022, excluding abnormal Operation and Maintenance expenses, if any, subject to prudence check by the Commission:

Provided that the average of such Operation and Maintenance expenses shall be considered as Operation and Maintenance expenses for the Year ended March 31, 2018, and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, to arrive at the Operation and Maintenance expenses for the base year ending March 31, 2023;

Provided further that the escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on the monthly Wholesale Price Index of the respective year as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, Government of India..

54.1.2 The Operation and Maintenance expenses for nth year of the Control Period shall be determined based on the formula shown below:

O&Mn = (R&Mn + EMPn + A&Gn) x (1 - Xn) + Terminal Liabilities and other one-time expenses

Where,

R&Mn –Repair and Maintenance Costs of Generating Station / Generating unit for the nth year;

EMPn –Employee Cost of Generating Station / Generating unit for the nth year;

A&Gn –Administrative and General Costs of Generating Station / Generating unit for the nth year;

Xn -Efficiency factor for nth Year. Value of Xn to be considered as zero till such time the same is determined through a study by the Commission:

Provided that the Terminal Liabilities and other one-time expenses shall be allowed separately on actual basis subject to prudence check.

54.1.3 It should be ensured that all such expenses capitalized should not form a part of the O&M expenses being specified here. The above components shall be computed in the manner as specified below:

*(i) R&Mn = K * GFA * (1+Index Escn)*

*(ii) EMPn+ A&Gn= (EMPn-1 + A&Gn-1) * (1+Index Escn)*

Where,

‘K’ is a constant (expressed in %) governing the relationship between R&M costs and Gross Fixed Assets (GFA) for the Control Period. The value of ‘K’ will be calculated based on the R&M expenses and GFA for past ten years (or all available years in case of utilities operating for less than 10 years as on April 01, 2022) ending March 31, 2022 approved by the Commission, subject to prudence check and any other factor considered relevant by the Commission;

‘GFA’ is the Opening balance of the gross fixed assets of the nth year;

EMPn-1 - Employee Cost of Generating Station / Generating unit for the immediately preceding year;

Provided that for first year of control period EMPn-1 and A&Gn-1 shall mean Employee and A&G expenses of the year after the base year (FY 2022-23) i.e. FY 2023-24, as derived using the escalation rate for FY 2023-24 as mentioned below;

Index Esc means the average Inflation escalation to be considered on the basis of weightage of WPI and CPI respectively of the relevant year and to be computed as below:

*Index Escn = WECPI*CPIn + WEWPI*WPIn*

Whereby,

WECPI : Weightage of CPI Index and;

WEWPI: Weightage of WPI Index;

‘WPIn’ (expressed in %) means the average yearly inflation of Wholesale Price Index (all commodities) over the years for the nth year;

‘CPIn’ (expressed in %) means the average yearly inflation of Consumer Price Index (Industrial workers) over the years for the nth year.

Note: *Source for CPI and WPI calculation as under:*

Wholesale Price Index numbers as per Office of Economic Advisor, Ministry of Commerce & Industry, Government of India {Base Year: 2011-12 Series};

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India {Base Year: 2001=100}.

Provided further that the escalation rate for FY 2023-24 and for the complete control period i.e. FY 2024-25, FY 2025-26, FY 2026-27, FY 2027-28, and FY 2028-29 shall be computed by considering (WEWPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Consumer Price Index (CPI).

Provided further that, in the Truing-up of the O&M expenses norms for any particular year of the Control Period, the escalation rate shall be computed by considering (WEWPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Consumer Price Index (CPI).

Provided further that in case an existing generating station has been in operation for less than ten (10) years as on the date of effectiveness of these Regulations, the O&M expenses shall be allowed based on the average of the actual audited expenses available or as per the norms as specified for new generating station, whichever is lower, as the case may be, subject to prudence check.

Note:

(a) For Coal based Generating Stations of GSECL, WECPI:WEWPI is to be considered as 60:40.

(b) For Coal based Generating Stations of TPL, WECPI:WEWPI is to be considered as 40:60.

(c) For Lignite and Gas based Generating Stations WECPI:WEWPI is to be considered as 50:50 and 40:60 respectively.

(d) O&M expenses shall be allowed on normative basis and shall be trued-up only to the account of variation in Wholesale Price Index and Consumer Price Index.

(e) The impact of Wage Revision, if any, may be considered at the time of true-up for any Year, based on documentary evidence and justification to be submitted by the Petitioner. Provisioning of wage revision expenses shall not be considered as actual expenses at the time of true-up, and only expenses as actually incurred shall be considered.

(f) *Any variation in actual audited O&M expenses, subject to prudence check, and normative O&M cost excluding any abnormal expenses or wage revision shall be subject to the sharing of efficiency gains or losses as per framework specified in this Regulations.*

(g) *Water Charges shall be allowed separately as per actuals, based on water consumption depending upon type of plant, type of cooling water system etc., subject to prudence check: Provided that the Commission shall provisionally approve the Water Charges for each year of the Control Period based on the actual Water Charges as per latest Audited Accounts available for the Generating Company, subject to prudence check.*

(h) *For the purpose of estimation, the same Index Escn value as derived for FY 2023-24 shall be used for all years of the Control Period. However, at the time of true-up of any particular year, the Commission will consider the actual values of the WPI and CPI over past ten financial years including True-up year."*

O&M expenses for New Generating Stations:

5.15.17 As stated above, the existing GERC MYT Regulations, 2016 allow the O&M expenses for new Generating Stations based on per MW norms, in line with the approach adopted by the CERC in its Tariff Regulations, 2014.

5.15.18 The Operation and Maintenance expenses for new generating stations shall be determined based on the submissions made by the Applicant, Operation and Maintenance expenses for other similar Generating Stations and any other criteria as deemed appropriate by the Commission on case to case basis, subject to prudence check.

Escalation Factor:

5.15.19 The paras below provide the detailed computation of escalation factor as considered above for deriving the norms of new Generating Stations.

5.15.20 The table below shows the yearly inflation of WPI and CPI over the past years as well as inflation factor for coal-based, lignite-based and gas-based Generating Stations:

Table 29: Computation of Escalation factor

Financial Year	CPI	YoY %	WPI	YoY %	Coal Based		Lignite Based		Gas Based		Hydro Based	
					60.00 %	40.00 %	50.00 %	50.00 %	40.00 %	60.00 %	60.00 %	40.00 %
2012-13	215.17		106.90									
2013-14	236.00	9.68%	112.46	5.20%	5.81%	2.08%	4.84%	2.60%	3.87%	3.12%	5.81%	2.08%
2014-15	250.83	6.29%	113.88	1.26%	3.77%	0.50%	3.14%	0.63%	2.51%	0.76%	3.77%	0.50%

Financial Year	CPI	YoY %	WPI	YoY %	Coal Based		Lignite Based		Gas Based		Hydro Based	
					60.00%	40.00%	50.00%	50.00%	40.00%	60.00%	60.00%	40.00%
2015-16	265.00	5.65%	109.72	-3.65%	3.39%	-1.46%	2.82%	-1.83%	2.26%	-2.19%	3.39%	-1.46%
2016-17	275.92	4.12%	111.63	1.75%	2.47%	0.70%	2.06%	0.87%	1.65%	1.05%	2.47%	0.70%
2017-18	284.42	3.08%	114.88	2.90%	1.85%	1.16%	1.54%	1.45%	1.23%	1.74%	1.85%	1.16%
2018-19	299.92	5.45%	119.79	4.28%	3.27%	1.71%	2.72%	2.14%	2.18%	2.57%	3.27%	1.71%
2019-20	322.50	7.53%	121.80	1.68%	4.52%	0.67%	3.76%	0.84%	3.01%	1.01%	4.52%	0.67%
2020-21	338.69	5.02%	123.38	1.29%	3.01%	0.52%	2.51%	0.65%	2.01%	0.78%	3.01%	0.52%
2021-22	356.06	5.13%	139.41	13.00%	3.08%	5.20%	2.56%	6.50%	2.05%	7.80%	3.08%	5.20%
2022-23	377.62	6.05%	152.51	9.40%	3.63%	3.76%	3.03%	4.70%	2.42%	5.64%	3.63%	3.76%

5.15.21 For determination of inflation factor in case new Coal-based Generating Stations, the CPI:WPI weightage has been considered as 60%:40% and for Lignite-based as 50%:50% and Gas-based Generating Stations the CPI:WPI weightage has been considered as 40%:60%.

5.15.22 The Commission is of the view that separate O&M expenses would be required in case of Emission Control System, for coal or lignite based thermal power generation utilities. Hence, the Commission has introduced Regulation 54.3 in accordance with the CERC Tariff Regulations 2019 and the same has been produced below:

> *“The operation and maintenance expenses on account of Emission Control System in coal or lignite based thermal generating station shall be 2% of the admitted capital expenditure (excluding interest during construction) as on its date of commercial operation, which shall be escalated annually @3.5% during the Control Period ending on 31st March 2025:*
> *Provided that income generated from sale of gypsum or other by-products shall be reduced from the operation and maintenance expenses*
>
> *Provided that income generated from sale of gypsum or other by-products shall be reduced from the operation and maintenance expenses.*”

5.16 Norms of operation for Hydro Generating Stations

5.16.1 Regulation 56 of the GERC MYT Regulations, 2016 specifies Normative Annual Plant Availability Factor (NAPAF) and Auxiliary Energy Consumption (AEC) including Transformer Losses for Hydro Power Plants.

5.16.2 The table below provides the summary of actual PAF data from FY 2017-18 to FY 2021-22 with respect to GSECL and TPL-G’s Generating Stations as approved during the true up of respective years:

Table 30: Actual PAF of Existing Stations/Units (kcal/kWh) for hydro Generating Stations

Power Station	FY 2017-2018	FY 2018-2019	FY 2019-2020	FY 2020-2021	FY 2021-2022	FY 2022-23	Average
Ukai Hydro	96.55%	96.74%	87.37%	76.62%	85.47%	94.41%	88.45%
Kadana Hydro	92.29%	91.79%	88.91%	90.71%	79.93%	79.15%	85.88%

5.16.3 The Hydro generating station of GSECL has shown capability of achieving higher PAF than the NAPAF of 80%. As the plants are old, it is suggested that the target availability for the Hydro generating stations may be retained at 80%.

5.17 Operation and Maintenance Expenses for Hydro Generating Stations

5.17.1 As per the existing provision under the GERC MYT Regulations, 2016, the O&M expenses norms have been specified for new Generating Stations in terms of percentage of the project cost for the first year and a fixed escalation rate of 5.72% has been provided for the future years. However, for existing Generating Stations, the O&M expenses was specified to be arrived based on an escalation rate of 5.72% over the past approved O&M expenses

5.17.2 Further, CERC in its Tariff Regulations, 2019 has specified the station wise normative O&M expenses for the existing Hydro Generating Stations. However, for new Hydro Generating Stations, the norms have been specified in terms of percentage of the project cost and escalation rate has been specified based on the installed capacities. Considering that the existing Hydro Generating Stations are very old, the Commission in the GERC MYT Regulations, 2016 has specified the principles to derive O&M expenses because of difficulties in specifying the norms. The Commission for the next Control Period also proposes to continue with the existing approach for specifying principle to derive O&M expenses rather than norms for the hydro Generating Stations/units.

O&M expenses for Existing Generating Stations:

5.17.3 O&M expenses comprises of R&M expenses, Employee expenses and A&G expenses, which constitute a significant part of the ARR. For deriving the O&M expenses of Hydro Generating Stations for the next Control Period, the same approach has been adopted as proposed for thermal Generating Stations, which has been explained in detail in above paras of this Explanatory Memorandum. Accordingly, for Hydro Generating Stations also, the Commission has proposed to adopt the WPI:CPI indexation mechanism. Similarly, for R&M expenses, it is proposed to have relationship between R&M expenses and Gross Fixed Asset by a constant factor 'K' to have true reflection of R&M expenses. The value of 'K' will be determined by the Commission in the MYT Order which shall be based on ratio of past period average of actual R&M expenses and Opening Gross Fixed Asset. However, the Generating Company may propose their K factor with sufficient reasoning at the time of filing of MYT Tariff Petition.

5.17.4 In regards to the determination of the weightages to be assigned to WPI and CPI index for calculation of inflation factor, based the data submitted by the utilities, the Commission has analysed the actual O&M expenses incurred by Hydro Generating Stations over the past years from FY 2012-13 to FY 2021-22 and has worked out the ratios viz. employee expenses to the total O&M expenses and A&G and R&M expenses to the total O&M expenses. The average ratio of employee expenses to the total O&M expenses across the aforesaid period has been considered as CPI weightage and the average ratio of A&G and R&M expenses to the total O&M expenses has been considered as a weightage of WPI.

5.17.5 The table below shows the employee expenses as a percentage of total actual O&M expenses for hydro Generating Stations of GSEC:

Table 31: Employee expenses as percentage of O&M expenses for hydro Generating Stations of GSECL

Name of the Plant	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	Average (10 Years)
Ukai Hydro	59.17 %	81.56 %	40.45 %	77.21 %	57.78 %	75.59 %	83.53 %	63.80 %	44.54 %	62.06 %	64.57 %
Kadana Hydro	52.06 %	62.26 %	74.54 %	75.80 %	65.38 %	45.79 %	59.21 %	64.87 %	66.24 %	60.96 %	62.71 %
Average											63.64 %

5.17.6 From the above table it can be observed that the employee expenses as a percentage of O&M expenses for GSECL's existing hydro Generating Station ranges from 40.45% to 83.53%. For determination of the weightage of the CPI, the Commission has considered the percentage of average actual employee expenses as percentage of the total O&M expenses of the GSECL's Generations Stations for the period FY 2012-13 to FY 2021-22, which is worked out as 63.64% (absolute 60% considered) as shown in the above table. Accordingly, the remaining part, i.e., 40% (100%-60%) has been assigned to WPI. Hence, it is proposed to consider the CPI:WPI as 60:40 for hydro Generating Stations.

5.17.7 The paragraphs below provide the methodology to calculate O&M expenses:

a) Calculate the average the actual audited Operation and Maintenance expenses (excluding water charges, Provisions and abnormal expenses etc.) for the past ten Years ending March 31, 2022. The average of all three components of O&M expenses; Employee expenses, R&M expenses and A&G expenses is to be calculated individually.

b) The average of such O&M expenses as computed above shall be considered as O&M expenses for the Year ended March 31, 2018 and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, to arrive at the Operation and Maintenance expenses for the base year ending March 31, 2023.

c) Provided further that the escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on the monthly Wholesale Price Index of the respective financial year as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, Government of India.

d) The O&M expenses for first year and subsequent years of the Control Period shall be determined based on the formula specified in the draft Regulations, as reproduced below:

    i. R&Mn = K * GFA * (1+Index Escn)

    ii. EMPn+ A&Gn= (EMPn-1 + A&Gn-1) * (1+Index Escn)

e) However, for the first year of the Control Period, EMP_{n-1} and $A\&G_{n-1}$ shall mean Employee and A&G expenses of the year after the base year (FY 2022-23) i.e. FY 2023-24, as derived using the escalation rate for FY 2023-24 as mentioned below. Thereafter, from second year of the Control Period, EMP_{n-1} and $A\&G_{n-1}$ shall mean Employee and A&G expenses of the immediately preceding year.

f) For the purpose of estimation of O&M expenses for the MYT Control Period, the same inflation factor as determined for FY 2022-23 shall be used for all years of the Control Period. However, at the time of truing-up of any particular year of the Control Period, the Commission shall calculate revised normative O&M expenses on the basis of actual inflation factor, which is to be derived based on the moving average of actual values/yearly inflation of WPI and CPI of the respective past ten financial years (including the year of Truing up).

5.17.8 The Commission also proposes to include the relevant clauses towards Wage Revision. These expenses shall be allowed on actual basis based on documentary evidence and justification of Generating Company subjected to prudence check at the time of truing up. The Commission shall not allow any wage revision on the basis of provisioning and shall only allow actual expenses at the time of Truing-up.

5.17.9 Therefore, the Commission has proposed the following proviso in relation to determination of O&M expenses for existing hydro generating station:

"56 Operation and Maintenance Expenses for Hydro Generating Stations

56.1 For Existing Stations:

56.1.1 The Operation and Maintenance expenses shall be derived on the basis of the average of the actual audited Operation and Maintenance expenses for the past ten financial years ending March 31, 2022, excluding abnormal Operation and Maintenance expenses, if any, subject to prudence check by the Commission:

Provided that the average of such Operation and Maintenance expenses shall be considered as Operation and Maintenance expenses for the Year ended March 31, 2018, and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, to arrive at the Operation and Maintenance expenses for the base year ending March 31, 2023;

Provided further that the escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on the monthly Wholesale Price Index of the respective financial year as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, Government of India.

56.1.2 The Operation and Maintenance expenses for nth year of the Control Period shall be determined based on the formula shown below:

O&Mn = (R&Mn + EMPn + A&Gn) x (1 – Xn) + Terminal Liabilities and other one-time expenses

Where,

R&Mn –Repair and Maintenance Costs of Generating Station / Generating unit for the nth year;

EMPn –Employee Cost of Generating Station / Generating unit for the nth year;

A&Gn –Administrative and General Costs of Generating Station / Generating unit for the nth year;

Xn -Efficiency factor for nth Year. Value of Xn to be considered as zero till such time the same is determined through a study by the Commission:

Provided that the Terminal Liabilities and other one-time expenses shall be allowed separately on actual basis subject to prudence check.

It should be ensured that all such expenses capitalized should not form a part of the O&M expenses being specified here. The above components shall be computed in the manner as specified below:

*(i) R&Mn = K * GFA * (1+Index Escn)*

*(ii) EMPn+ A&Gn= (EMPn-1 + A&Gn-1) * (1+Index Escn)*

Where,

'K' is a constant (expressed in %) governing the relationship between R&M costs and Gross Fixed Assets (GFA) for the Control Period. The value of 'K' will be calculated based on the R&M expenses and GFA for past ten years (or all available years in case of utilities operating for less than 10 years as on April 01, 2022) ending March 31, 2022 approved by the Commission, subject to prudence check and any other factor considered relevant by the Commission;

'GFA' is the Opening balance of the gross fixed assets of the nth year;

EMPn-1 - Employee Cost of Generating Station / Generating unit for the immediately preceding year;

A&Gn-1- A&G of Generating Station / Generating unit for the immediately preceding year;

Provided that for first year of control period EMPn-1 and A&Gn-1 shall mean Employee and A&G expenses of the year after the base year (FY 2022-23) i.e. FY 2023-24, as derived using the escalation rate for FY 2023-24 as mentioned below;

Index Esc means the average Inflation escalation to be considered on the basis of weightage of WPI and CPI respectively of the relevant year and to be computed as below:

*Index Escn = WECPI*CPIn + WEWPI*WPIn*

Whereby,

WECPI : Weightage of CPI Index and;

WEWPI : Weightage of WPI Index;

'WPIn' (expressed in %) means the average yearly inflation of Wholesale Price Index (all commodities) over the years for the nth year;

'CPIn' (expressed in %) means the average yearly inflation of Consumer Price Index (Industrial workers) over the years for the nth year.

Note: *Source for CPI and WPI calculation as under:*

Wholesale Price Index numbers as per Office of Economic Advisor, Ministry of Commerce & Industry, Government of India {Base Year: 2011-12 Series};

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India {Base Year: 2001=100}

Provided further that the escalation rate for FY 2023-24 and for the complete control period i.e. FY 2024-25, FY 2025-26, FY 2026-27, FY 2027-28, and FY 2028-29 shall be computed by considering (WEWPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Consumer Price Index (CPI).

Provided further that, in the Truing-up of the O&M expenses for any particular year of the Control Period, the escalation rate shall be computed by considering (WEWPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Consumer Price Index (CPI).

Note:

(a) For Hydro based generating stations WECPI:WEWPI is to be considered as 60:40.

(b) O&M expenses shall be allowed on normative basis and shall be trued-up only to the account of variation in Wholesale Price Index and Consumer Price Index.

(c) The impact of Wage Revision, if any, may be considered at the time of true-up for any year, based on documentary evidence and justification to be submitted by the Petitioner. Provisioning of wage revision expenses shall not be considered as actual expenses at the time of true-up, and only expenses as actually incurred shall be considered.

(d) Any variation in actual and normative O&M cost excluding any abnormal expenses or wage revision shall be subject to the sharing of efficiency gains or losses as per framework specified in this Regulations.

(e) For the purpose of estimation, the same Index Escn value as derived for FY 2024-25 shall be used for all years of the Control Period. However, at the time of true-up of any particular year the Commission will consider the actual values of the WPI and CPI over past ten years including True-up year.

56.2 For New Stations:

(a) O&M expenses for the first year of operation will be 2% of the original project cost on pro rata basis from the date of CoD (excluding cost of rehabilitation and resettlement works).

(b) The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above, at the escalation rate equal to 'Index Esc' specified in Regulation 56.1.2of these Regulations."

5.18 Computation and Payment of Annual Capacity Charges for Thermal Generating Stations

5.18.1 The GERC MYT Regulations, 2016 provides computation methodology for payment of monthly capacity charges based on the PAF.

5.18.2 The Commission did not propose any changes in the existing capacity charges payment computation in the draft GERC MYT Regulations, 2023.

5.19 Deviation Charges

5.19.1 Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 (hereinafter referred to as 'CERC DSM

Regulations') was introduced and made effective from February 17, 2014 and was amended three times. Accordingly, the Deviation Settlement Mechanism was implemented at Intra-State level effective from February 17, 2014 vide Letter No. GERC/Legal/2015/0436 dated March 5, 2015 by the Commission.

5.19.2 Further, the CERC has notified the Fourth amendment for the Deviation Settlement Mechanism (DSM) Regulations. The Commission vide its Order No. 1776 of 2019 dated December 27, 2019 has adopted these Regulations to larger extent.

5.19.3 As per the said amendment in DSM Regulations, an additional deviation charges have been implemented with regards to:

a) Conditions for Deviation Volume Limit and consequences of exceeding such Deviation Volume Limit by way of levy of Additional Deviation Charges as specified under Regulation;

b) Due to deviation by generating company or distribution licensee in a particular grid frequency as specified in the Regulations.

c) In the event of sustained deviation from schedule in one direction (positive or negative) by any regional entity (buyer or seller),

5.19.4 Accordingly, the Commission has proposed to modify the MYT Regulations in relation to Deviation Charges in line with the aforesaid CERC DSM Regulations whereby no UI charges including Additional UI Charges, related to any deviation in schedule payable or earned by Generating company will be allowed to be pass through to the beneficiaries and need to be borne by the Generating Company. However, demand being a dynamic in nature and being very volatile, it is proposed that such normal deviation charges paid or earned by the Distribution licensee will be allowed as a passthrough, however additional charges will not be allowed to be pass on to the consumers.

"65. Deviation Charges

65.1 All variations between actual net injection and scheduled net injection for generating plant, and all variations between actual net drawl and schedule net drawl for beneficiaries shall be treated as their respective deviations and will be dealt with as per the intra-State ABT Regulations/Orders notified/issued by the Commission including all its amendment from time to time.

65.2.Variations between actual net injection and scheduled net injection for the generating stations, and variations between actual net drawal and scheduled net drawal for the Beneficiary/ies shall be treated as their respective Unscheduled Interchange (deviations), and charges for such Unscheduled Interchange *(deviations) shall be governed in accordance with the Intra-State ABT Mechanism Order/Regulations issued by the Gujarat Electricity Regulatory Commission including all its amendment from time to time:*

Provided that any Unscheduled Interchange (deviations) Charges and any penalty or incentive, paid or earned by the Generating Company/ies in accordance with such Order/Regulations as issued by Commission shall not be recoverable/adjusted from the Beneficiary/ies through Tariff:

Provided further that basic Unscheduled Interchange (deviations) Charges paid or earned by the Distribution Licensees in accordance with such Intra-State ABT Mechanism Order/Regulations issued by the Commission including all its amendment from time to time shall be recoverable/adjusted from the Beneficiary/ies through Tariff:

Provided also that any Additional Charges applicable due to deviation in excess of the volume limit specified or sign violation to the Distribution Licensees in accordance with such Intra-State ABT Mechanism Order issued by the Commission including all its amendment from time to time, shall not be recoverable from the Beneficiary/ies through Tariff.”

5.20 Norms for Working Capital.

5.20.1 CERC in its recent Staff Paper has proposed “Deterrent Charges” for maintaining lower coal stock by coal based thermal generating stations as follows:

5.20.2 Domestic Coal Based Plant: If availability is less by 5% or more from the Normative Availability (as applicable) on quarterly basis, the Fixed charge shall be reduced to the extent of shortfall in Normative Availability and in addition the reduction below the Normative Availability shall be multiplied by a factor of 0.2 (i.e., levy of additional 20% due to reduced availability) to determine the penalty for non-maintenance of coal stock on quarterly basis.

5.20.3 Imported Coal Based Plant: If availability is less by 5% or more from the Normative Availability (as applicable) on quarterly basis, the Fixed charge shall be reduced to the extent of shortfall in Normative Availability, in addition the reduction below the Normative Availability shall be multiplied by a factor of 0.5 (i.e., levy /of additional 50% due to reduced availability) to determine the penalty for non-maintenance of coal stock on quarterly basis.

5.20.4 Further, if availability is less than 25% or more from the Normative Availability (as applicable) on quarterly basis, the Fixed charge shall be reduced to the extent of shortfall in Normative Availability and in addition the reduction beyond 25% below the

Normative Availability shall be multiplied by a factor of 1 (one) (i.e., levy of additional 100% due to reduced availability) to determine the penalty for non-maintenance of coal stock on quarterly basis.

5.20.5 GSECL has submitted that its thermal generating stations are non-pithead stations. The distance between coal source and GSECL's power plants is more than 1000 kms. Hence, to avoid coal shortages and subsequent generation loss, sufficient stock of coal is required to be maintained. Reviewing the norms of primary and secondary fuel cost in working capital in line with CERC may not be appropriate.

5.20.6 Cost of coal or lignite and limestone for 20 days month for pit-head generating stations and 30 days for non-pit-head generating stations, corresponding to target availability. Further, for the purpose of Truing up, the working capital shall be computed based on the actual average stock of coal or lignite and limestone or normative stock of coal or lignite and limestone of the generating Station, whichever is lower.

5.21 Differential Capacity Charges based on availability during Peak Requirement

5.21.1 The GERC MYT Regulations, 2016 does not provides any differential Capacity Charges based on availability during Peak Requirement. CERC in its Tariff Regulation for the FY 2019-24 tariff period, introduced the concept of peak and off-peak tariff for thermal generating stations to incentivise peak period availability and availability during peak demand season. Further, the Tariff Policy also specifies that differential rates for fixed charges should be introduced. By introducing the mandatory requirement of achieving target availability during peak hours and during high demand season, the generating stations were incentivised to be available during the time beneficiaries needed them the most. The Regulations stipulate the requirement for the generating stations to maintain specified target availability against the regional peak hours/demand season as declared by RLDCs.

5.21.2 Introduction of such differential capacity charges during peak period would motivate higher availability factor and achieving target availability by the generating station, thus making the generating stations available during the hours most required by the beneficiaries. However, constraints may be faced in declaration the high demand and low demand season as the same needs to be notified in advance. Further, the same needs to coincide with the demand and supply forecast.

5.21.3 After issuance of the CERC (Terms and Conditions of Tariff) Regulations, 2019, few of the SERCs adopted the revised CERC approach of differential capacity charges during peak period, while many of them have continued with the old approach mentioned in CERC (Terms and Conditions of Tariff) Regulations, 2014. Further, CERC in its Approach Paper – CERC MYT Regulations for 2024-29 has now proposed deliberations on recovery based on daily peak and off-peak periods also. Accordingly, following few alternatives were proposed in the discussion paper.

1. To continue with existing methodology based on CERC Tariff Regulations, 2014
2. To adopt revised methodology of month-wise peak/off-peak/normal seasons based on CERC Tariff Regulations, 2019
3. CERC Approach Paper for 2024 Tariff Regulations has proposed the option of recovery based on daily peak and off-peak periods.

5.21.4 GUVNL proposed that higher availability of generator during peak period / season will help in meeting consumers demand in most economical manner. The payment of capacity charge based on availability declared by generator during month-wise peak / off-peak period will bring more discipline and prompt generator to be available during peak period/season to recover capacity charges. Therefore, it would be appropriate to introduce methodology of recovery of capacity charges based on month-wise peak /off peak period/season wise availability declared by generator. Further, GuVNL requested the Commission to provide Gujarat SLDC in consultation with DISCOMs to notify peak/off-peak months and peak/off peak hours from time to time. Moreover, generator should ensure availability of adequate fuel for generation of electricity corresponding to declared availability during peak period/season.

5.21.5 APL suggested that differential capacity charges shall be considered as per notified CERC Tariff Regulations.

5.21.6 Prayas (Energy group) suggested that PLF incentive is primarily required in peak demand periods to incentivise low-cost generation from non-pithead plants by encouraging them to procure low-cost coal so that they are high on the MoD stack. The incentive is over-and-above the cost of procuring coal which is anyway pass-through (and over-and-above the RoE to the developer) – hence it can be modest. The incentives considered in the discussion paper (in line with CERC Regulations) of Rs. 0.65/kWh in peak hours and Rs. 0.5/kWh in non-peak hours are very high and should be revisited. On the other hand, higher availability should not be additionally incentivised, but AFC should be pro rata reduced for availability below the norm. There is value in encouraging plants to be available during peak hours. Going forward, the Commission should consider increasing the AFC weightage for peak hours and high demand months/seasons, as coal-based and hydro plants are likely to increasingly be required to supply electricity primarily during peak demand periods. CERC and MERC Regulations have these provisions for peak hours, though they can be strengthened further. Further, toward the differential capacity, since the objective of providing greater weightage for availability during peak is to encourage availability at times that they would be most required, it is suggested that the definition of 'peak periods' itself should be based on net load (i.e., after accounting for the must-run capacity such as solar and wind), rather than overall load. This should be the case since those are the periods when thermal and hydro plants would be most required. Toward this, the SLDC could submit net-load curves based on which the peak season/hours for each plant could be determined, and according to this, higher weightage for AFC recovery would be applicable.

5.21.7 The Commission is of the view that the implementation of differential capacity charges during the Peak / Off-Peak Mechanism would promote discipline in the generators and thus promote higher generation. Therefore, the Commission has introduced Regulation in line with CERC Tariff Regulations 2019, same has been produced below:

"57 Computation and Payment of Annual Capacity Charges and Energy Charges for Thermal Generating Stations

Capacity Charges

57.1 The fixed cost of a thermal generating station shall be computed on annual basis based on the norms specified under these regulations and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. The capacity charge shall be recovered under two segments of the year, i.e. High Demand Season (period of three months) and Low Demand Season (period of remaining nine months), and within each season in two parts viz., Capacity Charge for Peak Hours of the month and Capacity Charge for Off-Peak Hours of the month as follows:

Capacity Charge for the Year (CCy) = Sum of Capacity Charge for three months of High Demand Season + Sum of Capacity Charge for nine months of Low Demand Season

57.2 The Capacity Charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

Capacity Charge for the Month (CCm) = Capacity Charge for Peak Hours of the Month (CCp) + Capacity Charge for Off-Peak Hours of the Month (CCop)

Where,

High Demand Season:

CCp1 = $\{0.20 \, x$ *AFC)* x *(1/12)* x $(PAFMp1/NAPAF)$ *subject to ceiling of (0.20* x *AFC)* x *(1/12)}*

CCp2 = $\{0.20 \, x$ *AFC)* x *(1/6)* x $(PAFMp2/NAPAF)$ *subject to ceiling of (0.20* x *AFC)* x *(1/6)} – CCp1*

CCp3 = {0.20 x AFC) x (1/4) x (PAFMp3/NAPAF) subject to ceiling of (0.20 x AFC) x (1/4)} – (CCp1 + CCp2)

CCop1 = {0.80 x AFC) x (1/12) x (PAFMop1/NAPAF) subject to ceiling of (0.80 x AFC) x (1/12)}

CCop2 = {0.80 x AFC) x (1/6) x (PAFMop2/NAPAF) subject to ceiling of (0.80 x AFC) x (1/6)} – CCop1

CCop3 = {0.80 x AFC) x (1/4) x (PAFMop3/NAPAF) subject to ceiling of (0.80 x AFC) x (1/4)} – (CCop1 + CCop2)

Low Demand Season:

CCp1 = {0.20 x AFC) x (1/12) x (PAFMp1/NAPAF) subject to ceiling of (0.20 x AFC) x (1/12)}

CCp2 = {0.20 x AFC) x (1/6) x (PAFMp2/NAPAF) subject to ceiling of (0.20 x AFC) x (1/6)} – CCp1

CCp3 = {0.20 x AFC) x (1/4) x (PAFMp3/NAPAF) subject to ceiling of (0.20 x AFC) x (1/4)} – (CCp1 + CCp2)

CCp4 = {0.20 x AFC) x (1/3) x (PAFMp4/NAPAF) subject to ceiling of (0.20 x AFC) x (1/3)} – (CCp1 + CCp2 + CCp3)

CCp5 = {0.20 x AFC) x (5/12) x (PAFMp5/NAPAF) subject to ceiling of (0.20 x AFC) x (5/12)} – (CCp1 + CCp2 + CCp3 + CCp4)

CCp6 = {0.20 x AFC) x (1/2) x (PAFMp6/NAPAF) subject to ceiling of (0.20 x AFC) x (1/2)} – (CCp1 + CCp2 + CCp3 + CCp4 + CCp5)

CCp7 = {0.20 x AFC) x (7/12) x (PAFMp7/NAPAF) subject to ceiling of (0.20 x AFC) x (7/12)} – (CCp1 + CCp2 + CCp3 + CCp4 + CCp5 + CCp6)

CCp8 = {0.20 x AFC) x (2/3) x (PAFMp8/NAPAF) subject to ceiling of (0.20 x AFC) x (2/3)} – (CCp1 + CCp2 + CCp3 + CCp4 + + CCp5 + CCp6 + CCp7)

CCp9 = {0.20 x AFC) x (3/4) x (PAFMp9/NAPAF) subject to ceiling of (0.20 x AFC) x (3/4)} – (CCp1 + CCp2 + CCp3 + CCp4 + CCp5 + CCp6 + CCp7 + CCp8)

CCop1 = {0.80 x AFC) x (1/12) x (PAFMop1/NAPAF) subject to ceiling of (0.80 x AFC) x (1/12)}

CCop2 = {0.80 x AFC) x (1/6) x (PAFMop2/NAPAF) subject to ceiling of (0.80 x AFC) x (1/6)} – CCop1

CCop3 = {0.80 x AFC) x (1/4) x (PAFMop3/NAPAF) subject to ceiling of (0.80 x AFC) x (1/4)} – (CCop1 + CCop2)

CCop4 = {0.80 x AFC) x (1/3) x (PAFMop4/NAPAF) subject to ceiling of (0.80 x AFC) x (1/3)} – (CCop1 + CCop2 + CCop3)

CCop5 = {0.80 x AFC) x (5/12) x (PAFMop5/NAPAF) subject to ceiling of (0.80 x AFC) x (5/12)} – (CCop1 + CCop2 + CCop3 + CCop4)

CCop6 = {0.80 x AFC) x (1/2) x (PAFMop6/NAPAF) subject to ceiling of (0.80 x AFC) x (1/2)} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5)

CCop7 = {0.80 x AFC) x (7/12) x (PAFMop7/NAPAF) subject to ceiling of (0.80 x AFC) x (7/12)} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6)

CCop8 = {0.80 x AFC) x (2/3) x (PAFMop8/NAPAF) subject to ceiling of (0.80 x AFC) x (2/3)} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7)

CCop9 = {0.80 x AFC) x (3/4) x (PAFMop9/NAPAF) subject to ceiling of (0.80 x AFC) x (3/4)} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7 + CCop8)

Provided that in case of generating station or unit thereof under shutdown due to Renovation and Modernisation or installation of Emission Control System, as the case may be, the Generating Company shall be allowed to recover O&M expenses and interest on loan only;

Where,

CCm= Capacity Charge for the Month;

CCp= Capacity Charge for the Peak Hours of the Month;

CCop= Capacity Charge for the Off-Peak Hours of the Month;

CCpn= Capacity Charge for the Peak Hours of nth Month in a specific Season;

CCopn= Capacity Charge for the Off-Peak of nth Month in a specific Season;

AFC = Annual Fixed Cost;

PAFMpn = Plant Availability Factor achieved during Peak Hours upto the end of nth Month in a Season;

PAFMopn = Plant Availability Factor achieved during Off-Peak Hours upto the end of nth Month in a Season;

NAPAF= Normative Annual Plant Availability Factor.

57.3 Normative Plant Availability Factor for "Peak" and "Off-Peak" Hours in a month shall be equivalent to the NAPAF specified in Regulations 53.1 of these Regulations. The number of hours of "Peak" and "Off-Peak" periods during a day shall be four and twenty respectively. The hours of Peak and Off-Peak periods during a day shall be declared by the SLDC at least a week in advance. The High Demand Season period of three months, consecutive or otherwise) and Low Demand Season (period of remaining nine months, consecutive or otherwise) in the State shall be declared by the SLDC, at least six months in advance:

Provided that the SLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours and High Demand Season in such a way as to coincide with the Peak Hours and High Demand Season of the State.

57.4 Any under-recovery or over-recovery of Capacity Charge as a result of under-achievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of a Season (High Demand Season or Low Demand Season, as the case may be) shall not be adjusted with under-achievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of the other Season:

Provided that within a Season, the shortfall in recovery of Capacity Charge for cumulative Off-Peak Hours derived based on NAPAF, shall be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Peak Hours in that Season:

Provided further that within a Season, the shortfall in recovery of Capacity Charge for cumulative Peak Hours derived based on NAPAF, shall not be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Off-Peak Hours in that Season:

Provided also that full Capacity Charges shall be recoverable at target availability specified in Regulations 53.1 of these Regulations, and recovery of Capacity Charges below the level of Target Availability shall be on pro-rata basis, irrespective of the reasons for the lower Availability, and no part of the Capacity Charges shall be recoverable except to the extent of Availability:

Provided also that at zero availability, no Capacity Charges shall be payable.

57.5 Power plant designed on domestic coal: In the event the availability is less by 5% or more from the Normative Availability (as applicable) on quarterly basis, the fixed charge shall be reduced to the extent of shortfall in Normative Availability and in addition, the reduction below the Normative Availability shall be multiplied by a factor of 0.2 (i.e levy of additional 20% due to reduced availability) to determine the penalty for non-maintenance of coal stock on quarterly basis.

57.6 Power plant designed on imported coal: In the event the availability is less by 5% or more from the Normative Availability (as applicable) on quarterly basis, the fixed charge shall be reduced to the extent of shortfall in Normative Availability and in addition, the reduction below the Normative Availability shall be multiplied by a factor of 0.5 (i.e levy /of additional 50% due to reduced availability) to determine the penalty for non-maintenance of coal stock on quarterly basis.

57.7 All Power plants (designed on domestic coal and imported coal): Further, in case the availability is less by 25% or more from the Normative Availability (as applicable) on quarterly basis, the fixed charge shall be reduced to the extent of *shortfall in Normative Availability and in addition, the reduction beyond 25% below the Normative Availability shall be multiplied by a factor of 1 (one) (i.e levy of additional 100% due to reduced availability) to determine the penalty for non-maintenance of coal stock on quarterly basis.*

57.8 The provisions under Regulations 57.1 to 57.4 of these Regulation shall come into force with effect from 1.4.2025. Till that date, the capacity charge for a thermal generating station determined under these regulations shall be recovered in accordance with the provisions contained in Regulations 58.1 to 58.4 of the Gujarat Electricity Regulatory Commission (Multi-Year Tariff) Regulations, 2016, subject to the condition that the NAPAF and NAPLF shall be taken as specified under these Regulations."

5.22 Compensation in relation to operation on account of backing down

5.22.1 The GERC MYT Regulations, 2016 does not provides any compensation of backing down of thermal Generating Stations. The CERC has notified the Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016 dated April 6, 2016 wherein, compensation mechanism has been provided for the inter-state thermal generating stations for compensation of the losses which incurs due to backing down and reserve shut down.

5.22.2 GSECL has submitted that on account of Huge RE Integration in the grid, the conventional thermal generating stations are mostly supplying balancing power into the grid. Since the nature of RE generation is erratic, often thermal stations are forced to operate at low load and also kept in Reserve Shut down (RSD). Also, the system operator directs thermal stations for frequent starts & stops resulting into deterioration of performance parameters like SHR, secondary fuel consumption and auxiliary consumption etc. This causes heavy losses to generator. Also, maintenance cost increases. In the present tariff structure, no regulation provides for compensation to generator for such reasons beyond the control of it. Moreover, CERC has considered the compensation methodology prepared by Central Electricity Authority for operating a thermal (coal) generating unit below the 55% minimum power level based on the CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023. Accordingly, GSECL proposed to incorporate said methodology in the state regulations for determination of tariff for thermal generating stations and also to compensate the generator suitably for every start or stop instruction

5.22.3 It is observed that there has been significant capacity addition of Renewable Energy in the Country as well in the State of Gujarat. In view of the infirm nature of such generation and must run status of such renewable sources, it is essential that there is enough flexibility in generation to avoid demand supply mismatch and ensure grid stability. The hydro and gas based generation is natural fit for managing such a scenario. However, in view of the limited capacity of gas and hydro generation, it is essential that existing Thermal/Lignite based Generating Stations have enough flexibility so that SLDC can issue appropriate instructions for backing down. However, the Commission is also wary of the fact that frequent backing down, part load operation may impact performance parameters of the Generating Station. Therefore, the Commission feels that it is also necessary to ensure adequate compensation to be provided to Generating Station against the Degradation of Heat Rate, Aux Consumption and Secondary Fuel Oil Consumption, due to part load operation and multiple start/stop of units.

5.22.4 However, being a naïve arrangement, it is also necessary to undertake a proper technical and commercial study to elaborate on the methodology for calculation of such compensation and to verify such claims, so as to avoid any undue advantage to the Generating Company at the cost of burden on the consumers. Therefore, the Commission though keen to implement the compensation mechanism for the Generating utility for any degradation in operational parameters due to part load operation and multiple start/stop of units, the same may be undertaken at the time of true-up of Generating Station, on case to case basis, based on the data provided in the Petition along with the justification.

"66. Compensation in relation to operation on account of backing down

66.1. In case a Generating Station or Unit is instructed for backing down as per direction given by SLDC on account of grid security or due to the lower schedule given by the Beneficiaries, the impact of the same on any of the operational parameters such as Gross Station Heat Rate, Auxiliary consumption and Secondary Fuel Oil Consumption, may be considered by the Commission on case to case basis at time of truing up, subject to prudence check."

6 INTRA-STATE TRANSMISSION

6.1 O&M Expenses

6.1.1 In the GERC MYT Tariff Regulations, 2016, the O&M norms for Transmission Licensees are linked to Transmission line length (ckt-km) and sub-station related assets (number of bays). The escalation of the O&M expenses is done as per inflation for each year of the control period

6.1.2 The GERC MYT Regulations, 2016 provides for Operation and Maintenance expenses for a Transmission Licensee as follows:

"68. Calculation of Aggregate Revenue Requirement

….

68.2 Operation and Maintenance expenses:

68.2.1 Existing Transmission Licensee:

Gujarat Energy Transmission Company Ltd. (GETCO)

Table 14: O&M Expense norms in Rs. Lakh/Bay and Rs. Lakh/cktkm

Particulars	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21
O&M Expenses/ Bay	7.6000	8.0400	8.5000	8.9800	9.5000
O&M Expenses/ ckt-km	0.6400	0.6800	0.7200	0.7600	0.8100

Provided that the Transmission Licensee shall submit a certificate from the Chief Electrical Inspector for the number of bays and circuit kilometres of transmission line added during the year at the time of truing up.

68.2.2 For New Transmission Licensee:

For the New transmission licensees, the year-wise O&M norms shall be determined on case-to-case basis:

Provided that the same shall not be applicable to those new projects, which are awarded on a competitive bidding basis.

…."

6.1.3 For the next Control Period, the Commission proposes to continue with the same approach for deriving the O&M norms for the Transmission Licensee (GETCO) based on-line length in circuit km and number of bays

6.1.4 The O&M expenses will be derived based on the average Trued-Up values or based on audited accounts (Commission approved) for the last ten financial years. This average figure will be escalated on year-on-year basis with suitable escalation factor based on CPI and WPI of the respective financial years.

6.1.5 One-time expenses and expenses beyond the control of the Transmission Licensee may be allowed by the Commission over and above normative O&M expenses after prudence check.

Suggestion/Comment from Stakeholders:

1) FOKIA submitted that the O&M norms should be decided on the age of bays and transmission lines.
2) Adani Power Limited submitted that projecting O&M expenses based on past data of actual O&M expenses for a transmission project may not be prudent as the O&M expenses increase over a period of time due to various factors and therefore, the existing norms based on number of bays and transmission line in circuit kms. should be retained.
3) GETCO has submitted that based on the increase in O&M cost over the last 5 years, it is proposed to provide escalation factor of around 10% and rather than switching over mix of CPI & WPI indexation mechanism. Further, it is submitted that 2% O&M maintenance spares should be considered instead of 1% for the coastal/ special areas considering the atmospheric effect in coastal area and pollution prone industrial area.

Commission's View:

6.1.6 In the GERC MYT Regulations, 2016, the O&M norms for Transmission Licensees are linked to Transmission line length (circuit-km) and sub-station related assets (number of bays). The comments of all the stakeholders have been noted, and Commission proposes to continue with the same approach for deriving the O&M norms for the Transmission Licensees in the State of Gujarat based on-line length in circuit km and number of bays.

6.1.7 O&M expenses comprise of Employee expenses, Repair & Maintenance (R&M) expenses and Administrative & General (A&G) expenses. With increase in transmission capacity and corresponding increase in asset base, the manpower resources and repair and maintenance activities need to be augmented adequately to cater to the enhanced maintenance requirement (preventive and break-down) of the asset base. There is a direct correlation between O&M expenses and number of bays and length of transmission line (ckt-km) put into service.

6.1.8 Based on the data submitted by GETCO, the Commission has considered the 10-Year historical O&M Expenses till FY 2021-22 to project the O&M expenses for the fourth Control Period based on line length in circuit km and number of bays. It is assumed that 70% of the O&M expenses is obtained due to sub-station related assets (number of bays), and the remaining 30% expenses is obtained due to Transmission line length (ckt-km). O&M Expense Norms Projections for the next five years has been done using scenario analysis as follows:

Scenario 1:

In this scenario, projection of O&M Expenses / Bay and O&M Expenses/ ckt-km for next five years is as follows:

i. The five-year projection for number of bays and line length (from FY 2024-25 to FY 2028-29) is computed using the 5-year CAGR of the historical values.

ii. 5-year average (from FY 2017-18 to FY 2021-22) of actual O&M Expense per Bay and Line Length is used for the middle year (FY 2019-20) and escalated till the base year FY 2022-23, using the mix of 35% WPI and 65% CPI for each year.

iii. Further, 5-year average for FY 2022-23 (mix of 35% WPI and 65% CPI) is used as the escalation factor to project the O&M Expense per Bay and Line Length, for the next six years (from FY 2023-24 to FY 2028-29).

Table 32: Projected O&M Expense norms in Rs. Lakh/Bay and Rs. Lakh/ckt-km

Years	Number of average bays in each year	Line length (in Ckt-km) of lines in operation	O&M Expenses/ Bay (Projected) (INR lakh)	O&M Expenses/ ckt-km (Projected) (INR lakh)	Total O&M Expenses (Projected) (INR lakh)
2022-23 (Base Year)	15885.32	64472.56	8.36	0.83	186480.58
2023-24	16442.51	65685.34	8.85	0.88	203423.78
2024-25	17019.26	66920.92	9.36	0.93	221917.74
2025-26	17616.23	68179.76	9.91	0.99	242105.34
2026-27	18234.14	69462.26	10.50	1.05	264142.71
2027-28	18873.73	70768.90	11.11	1.11	288200.43
2028-29	19535.75	72100.11	11.76	1.17	314464.93

Scenario 2:

In this scenario, projection of O&M Expenses / Bay and O&M Expenses/ ckt-km for next five years is as follows:

i. The 5-year projection for number of bays and line length (from FY 2024-25 to FY 2028-29) is computed using 10-Year CAGR of the historical values.

ii. Further, 10-year average for FY 2022-23 (mix of 35% WPI and 65% CPI) is used as the escalation factor to project the O&M Expense per Bay and Line Length, for the next six years (from FY 2023-24 to FY 2028-29).

a) Scenario 2.1

In this scenario, projection of O&M Expenses / Bay and O&M Expenses/ ckt-km for next five years is as follows:

i. The five-year projection for number of bays and line length (from FY 2024-25 to FY 2028-29) is computed using 10-year CAGR of the historical values.

ii. 10-year average (from FY 2012-13 to FY 2021-22) of actual O&M Expense per Bay and Line Length is used for the middle year (FY 2017-18) and escalated till the base year FY 2022-23, using the actual CPI and WPI index with a mix of 35% WPI and 65% CPI for each year.

iii. Further, 10-Year average for FY 2022-23 (mix of 35% WPI and 65% CPI) is used as the escalation factor to project the O&M Expense per Bay and Line Length, for the next six years (from FY 2023-24 to FY 2028-29).

Table 33: Projected O&M Expense norms in Rs. Lakh/Bay and Rs. Lakh/ckt-km

Years	Number of average bays in each year	Line length (in Ckt-km) of lines in operation	O&M Expenses/ Bay (Projected) (INR Lakhs)	O&M Expenses/ ckt-km (Projected) (INR Lakhs)	Total O&M Expenses (Projected) (INR Lakhs)
2022-23 (Base Year)	16172.92	65304.42	8.30	0.79	185843.95
2023-24	17043.30	67391.28	8.72	0.83	204584.68
2024-25	17960.51	69544.82	9.16	0.87	225234.95

Years	Number of average bays in each year	Line length (in Ckt-km) of lines in operation	O&M Expenses/ Bay (Projected) (INR Lakhs)	O&M Expenses/ ckt-km (Projected) (INR Lakhs)	Total O&M Expenses (Projected) (INR Lakhs)
2025-26	18927.09	71767.19	9.62	0.92	247991.06
2026-27	19945.68	74060.57	10.11	0.96	273069.68
2027-28	21019.09	76427.24	10.62	1.01	300709.96
2028-29	22150.27	78869.54	11.16	1.06	331175.84

b) Scenario 2.2:

In this scenario, projection of O&M Expenses / Bay and O&M Expenses/ ckt-km for next five years is as follows:

i. The five-year projection for number of bays and line length (from FY 2024-25 to FY 2028-29) is computed using 10-year CAGR of the historical values.

ii. 10-year average (from FY 2012-13 to FY 2021-22) of actual O&M Expense per Bay and Line Length is used for the middle year (FY 2016-17) and escalated till our base year FY 2022-23, using the actual CPI and WPI index with a mix of 35% WPI and 65% CPI for each year.

iii. Further, 10-Year Average for FY 2022-23 (mix of 35% WPI and 65% CPI) is used as the escalation factor to project the O&M Expense per Bay and Line Length, for the next six years (from FY 2023-24 to FY 2028-28).

Table 34: Projected O&M Expense norms in Rs. Lakh/Bay and Rs. Lakh/ckt-km

Years	Number of average bays in each year	Line length (in Ckt-km) of lines in operation	O&M Expenses/ Bay (Projected) (INR lakh)	O&M Expenses/ ckt-km (Projected) (INR lakh)	Total O&M Expenses (Projected) (INR lakh)
2022-23 (Base Year)	16172.92	65304.42	8.55	0.82	191454.14
2023-24	17043.30	67391.28	8.98	0.86	210760.61
2024-25	17960.51	69544.82	9.43	0.90	232034.26

Years	Number of average bays in each year	Line length (in Ckt-km) of lines in operation	O&M Expenses/ Bay (Projected) (INR lakh)	O&M Expenses/ ckt-km (Projected) (INR lakh)	Total O&M Expenses (Projected) (INR lakh)
2025-26	18927.09	71767.19	9.91	0.95	255477.32
2026-27	19945.68	74060.57	10.41	0.99	281313.01
2027-28	21019.09	76427.24	10.94	1.04	309787.69
2028-29	22150.27	78869.54	11.50	1.10	341173.25

Note: 35% WPI and 65% CPI ratio was taken because the average % employee expenses/ Total O&M expenses for GETCO for the last ten years was approximately 65%. For the truing-up of each year in the next control period, 5-year moving average for that particular year (mix of 35% WPI and 65% CPI) will be used as the escalation factor to project the O&M Expenses per Bay and Line Length.

6.1.9 Considering all the three scenarios to compute the projected O&M expense norms for the next control period FY 2024-25 to FY 2028-29, the Commission proposes to use Scenario 2.1 for projecting the norms. The projected O&M Expense norms per Bay and O&M Expense norms per ckt-km are as follows:

Table 35: Projected O&M Expense norms in Rs. Lakh/Bay and Rs. Lakh/ckt-km

Years	O&M Expenses/ Bay (INR Lakhs)	O&M Expenses/ ckt-km (INR Lakhs)
2022-23 (Base Year)	8.30	0.79
2023-24	8.72	0.83
2024-25	9.16	0.87
2025-26	9.62	0.92
2026-27	10.11	0.96
2027-28	10.62	1.01
2028-29	11.16	1.06

6.1.10 The new O&M expense regulations are proposed as follows:

*“ **69 Operation and Maintenance expenses:***

69.1 The Operation and Maintenance expenses for Transmission Licensees shall be allowed based on the norms for Operation and Maintenance expenses derived for circuit kilometres of transmission lines and number of Bays as per methodology specified in clauses below:

69.2 Existing Transmission Licensee:

69.2.1 Norms for Operation and Maintenance expenses for existing Transmission Licensees shall be derived based on the average of the actual audited Operation and Maintenance expenses for the past ten Years ending March 31, 2022, excluding abnormal Operation and Maintenance expenses, if any, subject to prudence check by the Commission:

Provided that Terminal Liabilities and other one-time expenses shall be allowed separately on actual basis subject to prudence check:

Provided further that the average of such Operation and Maintenance expenses shall be allocated to bays and transmission line length (ckt-km) in the ratio of 70:30:

Provided further that the average Operation and Maintenance expenses allocated to bays and transmission line length (ckt-km) as computed above, shall be divided by average number of bays and transmission line length in ckt-km derived on the basis of opening and closing number of bays/ transmission line length, to arrive at Operation and Maintenance expenses per bays and Operation and Maintenance expenses per ckt-km:

Provided that such Operation and Maintenance expenses per bays and per ckt-km shall be considered as norms for Operation and Maintenance expenses for the Year ended March 31, 2018 and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, to arrive at the norms for Operation and Maintenance expenses per bays and per ckt-km for the base year ending March 31, 2023:

Provided further that the escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22, and FY 2022-23, shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on the monthly Wholesale Price Index of the respective financial year as per the

Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, Government of India..

69.2.2 *The norms for Operation and Maintenance expenses per bays and per ckt-km for nth year of the Control Period shall be determined based on the formula shown below:*

*i. O&M per bayn = (O&M per bayn-1) * (1+Index Escn)*

*ii. O&M per ckt-kmn= (O&M per ckt-kmn-1) * (1+Index Escn)*

Where,

O&M per bay$_{n-1}$ *– Norm for Operation and Maintenance expenses per bay for Transmission Licensee for the immediately preceding year;*

O&M per ckt-km$_{n-1}$ *– Norm for Operation and Maintenance expenses per ckt-km for Transmission Licensee for the immediately preceding year;*

Provided that for first year of control period, O&M per bay$_{n-1}$ *and O&M per ckt-km*$_{n-1}$ *shall mean norms for Operation and Maintenance expenses per bays and per ckt-km of the year after the base year (FY 2022-23) i.e. FY 2023-24, as derived using the escalation rate for FY 2023-24 as mentioned below;*

Index Esc means the average Inflation escalation to be considered based on weightage of WPI and CPI respectively of the relevant year and to be computed as below:

$Index\ Esc_n = WE_{CPI} * CPI_n + WE_{WPI} * WPI_n$

Whereby,

WE_{CPI} *: Weightage of CPI Index and;*

WE_{WPI}*: Weightage of WPI Index;*

'WPI_n*' (expressed in %) means the average yearly inflation of Wholesale Price Index (all commodities) over the years for the* n^{th} *year;*

'CPI_n*' (expressed in %) means the average yearly inflation of Consumer Price Index (Industrial workers) over the years for the* n^{th} *year.*

Note: *Source for CPI and WPI calculation as under:*

Wholesale Price Index numbers as per Office of Economic Advisor, Ministry of Commerce & Industry, Government of India {Base Year: 2011-12 Series};

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India {Base Year: 2001=100}

Provided further that the escalation rate for FY 2023-24 and for the complete control period i.e. FY 2024-25, FY 2025-26, FY 2026-27, FY 2027-28, and FY 2028-29 shall be computed by considering (WE_{WPI}) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Wholesale Price Index (WPI) and (WE_{CPI}) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Consumer Price Index (CPI).

Provided further that, in the Truing-up of the O&M expenses norms per bays and per ckt-km for any particular year of the Control Period, the escalation rate shall be computed by considering (WE_{WPI}) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Wholesale Price Index (WPI) and (WE_{CPI}) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Consumer Price Index (CPI)

Note:

(a) For Transmission Licensee WE_{CPI}:WE_{WPI} is to be considered as 65:35.

(b) O&M expenses shall be allowed on normative basis and shall be trued-up only to the account of variation in Wholesale Price Index and Consumer Price Index.

(c) The number of Bays considered for computing O&M expenses norms shall exclude the unutilised Bays.

(d) The O&M expenses for the GIS bays shall be allowed by multiplying 0.7 to the O&M expenses norms for bays of the respective year of control period as worked out in Regulation 69.2.2 above.

(e) The impact of Wage Revision, if any, may be considered at the time of true-up for any Year, based on documentary evidence and justification to be submitted by the Petitioner. Provisioning of wage revision expenses shall not be considered as actual expenses at the time of true-up, and only expenses as actually incurred shall be considered.

(f) For the purpose of estimation, the same Index Escn value as derived for FY 2023-24 shall be used for all years of the Control Period. However, at the time of true-up of any particular year the Commission will consider the actual values of the WPI and CPI over past ten years including True-up year.

(g) Any variation in actual and normative O&M cost excluding any abnormal expenses or wage revision shall be subject to the sharing of efficiency gains or losses as per framework specified in this Regulations.

(h) Transmission Licensee shall submit a certificate from the Chief Electrical Inspector for the number of bays and circuit kilometres of transmission line added during the year at the time of truing up.

69.3 For New Transmission Licensee:

69.3.1 For the New transmission licensees, the year-wise O&M norms shall be determined on case-to-case basis:

Provided that the Terminal Liabilities and other one-time expenses shall be allowed separately on actual basis subject to prudence check:

Provided further that the same shall not be applicable to those new projects, which are awarded on a competitive bidding basis.

Explanation 1: *The term "New Transmission Licensee" shall mean the Transmission Licensee(s) for which transmission license is granted by the Commission after the date of effectiveness of these Regulations, and whose transmission project assets are commissioned after March 31, 2024.*

Explanation 2: *For the purpose of deriving normative O&M expenses, 'Bay' shall mean 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 at Sub-station of Transmission Licensee. Further, the Bays referred herein shall include only the Bays at the Transmission substation and shall exclude any bays of the Generating Station switchyard whose maintenance is usually the responsibility of the Generating Company."*

6.2 Norms of working capital for Transmission Licensee

6.2.1 The GERC MYT Tariff Regulations, 2016 stipulate the following norms of working capital for Transmission Licensee:

“40 Interest on Working Capital

…

40.2 Transmission:

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

(i) Operation and maintenance expenses for one month; plus

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

(iii) Receivables equivalent to one (1) month of transmission charges calculated on target availability level;

minus

(iv) Amount, if any, held as security deposits except the security deposits held in the form of Bank Guarantee from Transmission System Users:

….”

Suggestion/Comment from Stakeholders:

1) Adani Power Limited has submitted that the existing practice of 1% of GFA may be continued as there is inbuilt incentive and penalty for the licensees based on the availability of lines as in case any licensee maintains higher availability using higher level of inventory of spares then such licensee may get higher working capital as compared to another licensee maintaining the same availability with lesser spares. It is further submitted that there should be no sharing of gains on operational parameters. Adani Power Limited has also submitted that if sharing is done, then 2/3rd should be retained by the licensee and 1/3rd should be passed on to the consumer. Along with the sharing of gains, sharing of losses should also be done in the same manner as proposed above.

<u>Commission’s View:</u>

6.2.2 The Commission has note the stakeholders comments and has reviewed & compared working capital norms with other States.

6.2.3 From the above analysis, it is observed that most Indian states consider 1 month O&M expenses for IoWC determination. Rajasthan, Madhya Pradesh, Himachal Pradesh, Punjab, and Maharashtra consider 15% of total O&M expenses for maintenance spares, while Maharashtra and Karnataka consider 1% of historical cost of assets.

6.2.4 From the comparison, it is observed that consideration of 1-month O&M expenses and 1% of Historical Cost (GFA) in existing GERC regulations is quite stringent in comparison to other state ERCs.

6.2.5 Considering the billing and recovery efficiency, as well as the current state of the STU, the Commission is of the view that maintaining the receivables equivalent to 1 month of the Annual Fixed Cost is sufficient for Transmission licensees to maintain their liquidity.

6.2.6 Therefore, the Commission has proposed the working capital norms as follows:

"38 Interest on Working Capital

…

38.2 Transmission:

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

(i) Operation and maintenance expenses for one month; plus
(ii) Maintenance spares at one (1) per cent of the opening Gross Fixed assets; plus
(iii) Receivables equivalent to one (1) month of transmission charges calculated on target availability level;
minus
(iv) Amount, if any, held as security deposits except the security deposits held in the form of Bank Guarantee from Transmission System Users:

Provided that at the time of truing up for any year, the working capital requirement shall be recalculated on the basis of the values of components of working capital approved by the Commission in the truing up before sharing of gains and losses;"

6.3 Transmission Loss

6.3.1 The GERC MYT Tariff Regulations, 2016 stipulate the following:

"75. Transmission losses

The energy losses in the transmission system of the Transmission Licensee, as determined by the State Load Despatch Centre, shall be borne by the Transmission System Users in proportion to their usage of the intra-State transmission system."

Suggestion/Comment from Stakeholders:

1) FOKIA submitted that while deciding targets for losses, capital investments made during the year should be taken into consideration.

2) Adani Power Limited submitted that there should also be an incentive for the transmission licensee to maintain the loss level in the transmission system below the range approved in MYT order, as it will improve the loss level in the transmission system. As per the present mechanism, only losses shall be passed onto the transmission licensees and benefits of maintaining losses below the range is proposed to be shared among the transmission system users only.

3) GUVNL has submitted that transmission loss is function of power flow condition in mesh network which is a function of power injection location in the network and location of drawl nodes. Thus, transmission loss in the network needs to treated as uncontrollable parameters, in line with approach taken by CERC in MYT tariff regulations 2019.

4) GETCO has submitted that the new high ampacity/HTLS conductors are needed for optimum utilization of land resource, but it will increase the Transmission Loss. If transmission losses will be considered for benchmarking of incentive and part of RoE than it will be prohibitive provision for adoption of such technologies. Thus, GETCO has submitted to exclude the Transmission Losses from the performance / assessment parameters.

Commission's View:

6.3.2 The GERC MYT Regulations, 2016 specified that the energy losses in the transmission system of the Transmission Licensee, shall be borne by the Transmission System Users as determined by the State Load Dispatch Centre in proportion to their usage of the intra-State transmission system.

6.3.3 Commission has reviewed regulations adopted by various other SERCs for Transmission loss treatment.

6.3.4 Addressing to the comments of the stakeholders, the Commission propose that in case the actual transmission loss levels achieved by the Transmission Licensee deviates on either side of a specific transmission loss band, then the Transmission Licensee shall be incentivized or penalized through variation in the rate of Return on Equity.

6.3.5 Therefore, the Commission has proposed the following Regulation regarding the Transmission Losses:

"75 Transmission losses:

75.1 The Commission shall examine the filing made by the transmission licensee in respect of transmission loss and shall approve a transmission loss trajectory band with upper and lower limits having ±0.10% variation for each year of the Control Period based on the opening loss levels, licensee's filings/submissions, past trends, objections raised by the stakeholders and any other factor considered relevant by the Commission. This approved loss target will be used for computing estimated energy for transmission in licensee's system for that year.

75.2 There shall be no incentive or penalty in case the actual transmission losses lies within the specified band determined for the year of the Control Period. However, in case the actual transmission loss levels achieved by the Transmission Licensee is deviates on either side of the loss band as provided above, then the

Transmission Licensee shall be incentivized or penalized, as the case may be, through variation in the rate of Return on Equity in accordance with Regulation 35 of these Regulations.

75.3 Energy losses in the transmission system of the Transmission Licensee, as determined by the Gujarat State Load Despatch Centre, shall be borne by the Transmission System Users in proportion to their usage of the intra-state transmission system.

Provided that the quantum of energy consumed by the auxiliary equipment of a transmission substation and the station transformer losses within the sub-station shall not be accounted for under the Transmission Losses:

Provided further that the energy consumed for supply of power by the transmission sub-station to the associated offices of the Licensee, its housing colony and other facilities, and for construction works at the sub-station, shall not be considered as energy consumed by the auxiliary equipment of a transmission sub-station:

Provided further that Transmission Licensee shall place the details of energy accounts (weekly/monthly settlements) of all the transmission system users, the month-wise transmission system availability as certified by SLDC, on it's website along with the transmission loss for a month, by the end of the succeeding month."

6.4 Development of Intra-State Transmission projects under TBCB

6.4.1 The Hon'ble Supreme Court through its judgement dated 23rd November 2022 in the Civil Appeal No. 1933 of 2022 directed that-

"130. ………." We are cognizant of the fact that in matters dealing with electricity regulation, the regulatory commissions and the transmission utilities are usually bogged down by factors such as technological uncertainty, requirement of heavy investment and issues of right of way. The ad-hoc functioning of the transmission utilities is also attributable to the lacunae in the regulations guiding the exercise of their functions. The Electricity Act 2003 was enacted with the objective of providing the States with sufficient flexibility to regulate the intra-state electricity system and simultaneously provided the regulatory commissions with the power to determine tariffs. Though the Government, both at the Centre and in the States, have framed statutory policies and guidelines regulating the electricity sector, we have noticed that the Regulatory Commissions have not framed the necessary regulations to put into effect the principles prescribed under the Act.
131. We direct all State Regulatory Commissions to frame Regulations under Section 181 of the Act on the terms and conditions for determination of tariff within three months from the date of this judgment. While framing these

guidelines on determination of tariff, the Appropriate Commission shall be guided by the principles prescribed in Section 61, which also includes the NEP and NTP. Where the Appropriate Commission(s) has already framed regulations, they shall be amended to include provisions on the criteria for choosing the modalities to determine the tariff, in case they have not been already included. The Commissions while being guided by the principles contained in Section 61 shall effectuate a balance that would create a sustainable model of electricity regulation in the States. The Regulatory Commission shall curate to the specific needs of the State while framing these regulations. Further, the regulations framed must be in consonance with the objective of the Electricity Act 2003, which is to enhance the investment of private stakeholders in the electricity regulatory sector so as to create a sustainable and effective system of tariff determination that is cost efficient so that such benefits percolate to the end consumers."

6.4.2 In view to above, GERC vide its Order in Suo Moto Petition No. 2171 of 2023, dated 7.3.2023 has notified Threshold limit of Rs. 100 Crore (excluding land cost) for all new and augmentation of Intra-State Transmission projects developed through Tariff Based Competitive Bidding (TBCB).

Suggestion/Comment from Stakeholders:

1) GETCO has submitted that Project developer/ Bidder is required to factor in the whole cost consisting of substation and connected upper and lower-level line network, while preparing the transmission works through competitive bidding. These costs surmount to not less than Rs. 250 crores. Therefore, GETCO has submitted to review the threshold limit for intra-state transmission projects selected through tariff based competitive bidding route to Rs. 250 crores instead of Rs. 100 crores.

Commission's View:

6.4.3 As mentioned in the discussion paper, it was observed that SERCs like Maharashtra, Himachal Pradesh and Uttarakhand have complied with the Hon'ble Supreme Court Judgement and amended their respective MYT Regulations. Accordingly, it was proposed that threshold limit in the capital expenditure approval guideline should be implemented in the new draft regulations.

6.4.4 The details of the amended MYT Regulations for MERC, HPERC and UERC are as follows:

ERC	Regulation Details	Threshold Limit Proposed (INR Crores)
MERC	Maharashtra Electricity Regulatory Commission (Multi Year Tariff) (First Amendment) Regulations, 2023 dated 10.2.2023	500
HPERC	Himachal Pradesh Electricity Regulatory Commission (Terms and Conditions for Determination of Transmission Tariff) (Third Amendment) Regulations, 2023 date 1.6.2023	45
UERC	Uttarakhand Electricity Regulatory Commission (Terms and Conditions for Determination of Multi Year Tariff) (First Amendment) Regulations, 2022 date 11.6.2022	100

6.4.5 The Commission proposes the following regulations, as given below:

“

64.2 ***For InSTS Projects under Section 63 of the Act:***

64.2.1 All new and augmentation of Intra-State Transmission projects of 220 kV & above voltage level (including associated equipment of downstream voltage level) or having estimated cost excluding land cost of more than 100 Crores, being part of the STU Transmission Plan, shall be implemented through Tariff Based Competitive Bidding (TBCB) in accordance with the guidelines issued under Section 63 of the Act and any deviation from the guidelines should have prior approval of the Commission. The tariff of such intra-state transmission projects shall be discovered under Section 63 of the Act:

Provided that following new greenfield intra-state transmission projects, being part of the STU Transmission Plan, shall be covered under RTM framework (under Section 62 of the Act) subject to prior approval of the Commission:

(a) Intra-state transmission projects of strategic importance or works required for catering to an urgent situation, where proposal of such importance or urgency is supported by the recommendation of the State Government;

(b) Deposit works, whose funds are accounted for under consumer contribution;

(c) Small schemes such as LILO lines, whether for the purpose of a city bypass or otherwise, and entailing a cost not exceeding Rs. 100 Crores. However, after completion of project, if it is found that the capital cost incurred has exceeded the ceiling limit of Rs 100 Crores, then such excess amount shall not be passed under Regulated Tariff and shall be borne by the transmission licensee through its own reserve/cost.

64.2.2 The State Transmission Utility (STU) i.e. GETCO to frame guidelines in this regard within four months from the date of notification of these regulations.

*64.3 **Tariff Determination for InSTS Projects under Section 62 of the Act:***

Tariff for all other intra-state transmission projects not covered under Regulation 64.2, being part of the STU Transmission Plan, shall be determined in accordance with RTM framework under Section 62 of the Act.

Implementation of augmentation/ strengthening works (excluding O&M works) at the intra-state transmission substation and/or line, being part of the STU Transmission Plan, shall be carried out by the respective developer in accordance with the provisions under Section 62 of the Act, for which the STU shall obtain prior approval of the Commission on case-to-case basis.…"

7 SLDC

7.1 Incorporating SLDC as a separate Entity from Transmission Licensee

7.1.1 Section 31 (1) and 31(2) of the Electricity Act, 2003, state as follows:

*"**Section 31. (Constitution of State Load Despatch Centres):** --- (1) The State Government shall establish a Centre to be known as the State Load Despatch Centre for the purposes of exercising the powers and discharging the functions under this Part.*

(2) The State Load Despatch Centre shall be operated by a Government company or any authority or corporation established or constituted by or under any State Act, as may be notified by the State Government:

Provided that until a Government company or any authority or corporation is notified by the State Government, the State Transmission Utility shall operate the State Load Dispatch Centre:

Provided further that no State Load Despatch Centre shall engage in the business of trading in electricity."

Commission's View:

7.1.2 Section 31 (1) and 31(2) of the Electricity Act, 2003 require the State Government to establish a separate State Load Despatch Centre (SLDC) and provides that the SLDC shall be operated by a Government authority constituted under any State Act and until such authority is notified by the State Government, the State Transmission Utility (STU) would operate the SLDC

7.1.3 Currently, Gujarat Energy Transmission Corporation Limited (GETCO) which operates as STU in Gujarat, oversees the operations of SLDC

7.1.4 The Commission proposes to separate SLDC as an entity from the STU (GETCO) and till this is done there may be some dis-incentivization on the rate of RoE component of the Transmission Licensee and SLDC. It is proposed that if the SLDC as an entity is not separated from GETCO by the beginning of the 3rd year of this Control Period, the Transmission Licensee as well as the SLDC will not be allowed any additional RoE as per the Regulations.

7.1.5 Hence, the Commission proposes the following regulations:

"35.9 From the beginning of third year of the Control Period, in case of Transmission Licensee- Gujarat Electricity Transmission Corporation Limited (GETCO) and SLDC, the additional rate of Return on Equity as mentioned in Regulation 35.7 and Regulation 35.8 of these Regulations, shall only be allowed, in case the

SLDC is constituted as a separate and independent legal entity from GETCO in accordance with the provisions of Section 31(2) of the Act. "

7.2 Capital Investment Plan

7.2.1 According to the GERC MYT Regulations, 2016, the Regulations regarding the Capital Investment Plan states as follows:

"78.1 The SLDC shall submit a detailed capital investment plan, financing plan and physical targets for each year to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period."

Commission's View:

7.2.2 According to the CABIL report published in December 2018, the SLDCs get a large amount of money approved for projects but they don't utilize it in the control period. Accordingly, negative reinforcements are proposed for SLDCs in the form of reduced rate of RoE, if they fell to utilize the capital approved within the control period.

7.2.3 Hence, the commission proposes following regulations for Capital Investment Plan for SLDC:

"80 Capital Investment Plan

80.1 SLDC shall submit a detailed capital investment plan, financing plan and physical targets for each year to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period based on the operational requirements prescribed by the Commission and recommendations of various Committees constituted for looking into matters related to strengthening of the State Load Despatch Centres by the Ministry of Power, Government of India or any such other statutory authorities, to the Commission for approval, as a part of the Aggregate Revenue Requirement for the entire Control Period.

80.2 SLDC shall submit the Capital Investment Plan as specified in Chapter 2 of these Regulations.

80.3 Capital Investment Plan shall be a least cost plan for undertaking investments and shall cover all capital expenditure projects of a value as specified in Guidelines for in-principle clearance of proposed investment schemes as provided in Annexure III of these Regulations or such other amount as may be stipulated by the Commission from time to time, and shall be in such form as may be stipulated.

80.4 Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required showing the need for the proposed *investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the SLDC Fees and Charges.*

80.5 The Commission shall consider the Capital Investment Plan along with the Aggregate Revenue Requirement for the entire Control Period submitted by the SLDC taking into consideration the prudence of the proposed expenditure and estimated impact on SLDC Fees and Charges.

80.6 SLDC shall submit, along with the Petition for determination of Aggregate Revenue Requirement on each year of the control period, details showing the progress of capital expenditure projects, together with such other information, particulars or documents as the Commission may require to assess such progress.

Provided also that the computation of penalty on the allowable RoE shall be undertaken as per Regulation 35 of these Regulations.

80.7 SLDC shall be required to ensure that the procurement of the assets have been undertaken in a competitive and transparent manner. Further the assets so capitalized as a part of the approved capital investment plan under these Regulations should necessarily be geo-tagged and properly recorded in Fixed Asset Register (FAR) for allowance of the capitalization of the same by the Commission.

Provided that regarding the assets already capitalized as on April 01, 2024, the SLDC shall prepare and submit to the Commission a time-bound plan to undertake the geo-tagging in phased manner, preferably within the Control Period, along with the MYT Petition.

Provided further that the SLDC must provide access of the details of geo-tagging to the Commission for online monitoring."

7.3 Norms of Working Capital for SLDC Business

7.3.1 The GERC MYT Tariff Regulations, 2016 stipulate the following norms of working capital for Transmission Licensee:

"40 Interest on Working Capital

…

40.3 SLDC:

(a) The SLDC shall be allowed interest on the estimated level of working capital for the

financial year, computed as follows:

(i) Operation and maintenance expenses for one month; plus

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

(iii) Receivables equivalent to 15 days of the expected revenue from SLDC Charges;

Provided that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up;

….."

Commission's View:

7.3.2 The working capital norms as per provisions GERC MYT Regulations, 2016 have been compared with the corresponding norms of other States, which is summarized as follows:

Table 36: Norms of Working Capital for SLDC Business adopted by ERCs

ERC	O&M Expenses	Maintenance Spares	Receivables Less Security Deposit
Gujarat	1 month	1% of Historical Cost (GFA)	15 days of Receivables of the expected revenue from SLDC charges
Maharashtra	1 month	Nil	1½ month of the expected revenue from levy of annual fixed charges approved by the Commission
Rajasthan	1 month	15% of O&M expenses	1½ month of transmission charges calculated on annual target availability level for transmission licensee Minus Security Deposits from Users other than those in the form of Bank Guarantees (same for transmission and SLDC)
Punjab	1 month	15% of O&M expenses	2 months of Receivables calculated on normative target availability (same for transmission and SLDC)

ERC	O&M Expenses	Maintenance Spares	Receivables Less Security Deposit
Himachal Pradesh	1 month	15% of O&M expenses for one month	2 months Receivables towards SLDC Charges
Delhi	NA	NA	NA
Uttarakhand	1 month	15% of O&M expenses	2 months Receivables
Madhya Pradesh	NA	NA	NA
Karnataka	NA	NA	NA

7.3.3 In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. From the comparison, it can be observed that consideration of 1-month O&M expenses and 1% of Historical Cost (GFA) in existing GERC regulations is quite stringent in comparison to other state ERCs.

7.3.4 Hence, the Commission proposes the following regulations for Working Capital norms for SLDC:

"38.3. SLDC

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

(i) Operation and maintenance expenses for one month; plus

(ii) Maintenance spares at one (1) per cent of the Opening GFA cost related to SCADA and RTU; plus

(iii) Receivables equivalent to 15 days of the expected revenue from SLDC Charges;

Provided that at the time of truing up for any year, the working capital requirement shall be recalculated on the basis of the values of components of working capital approved by the Commission in the truing up before sharing of gains and losses;"

7.4 Operation and Maintenance expenses:

7.4.1 Regulation 79.4 of the GERC MYT Regulations, 2016 specifies as follows:

"79.4 Operation and Maintenance expenses

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 three (3) years ending March 31, 2015, subject to prudence check by the Commission.

b) The average of such operation and maintenance expenses including insurance shall be considered as operation and maintenance expenses for the financial year ended March 31, 2014 and shall be escalated year on year at the escalation factor of 5.72% to arrive at operation and maintenance expenses for subsequent years up to FY 2020-21."

7.4.2 Further, at the time of truing-up, the Commission allows normative O&M expenses as per the provisions of the GERC MYT Regulations and allows the sharing of efficiency gains or losses as per the variation in normative O&M Expenses vis-à-vis actual O&M Expenses incurred by Distribution Licensee after prudence check.

7.4.3 The Discussion Paper has highlighted following issues with the existing approach of computing normative O&M expenses:

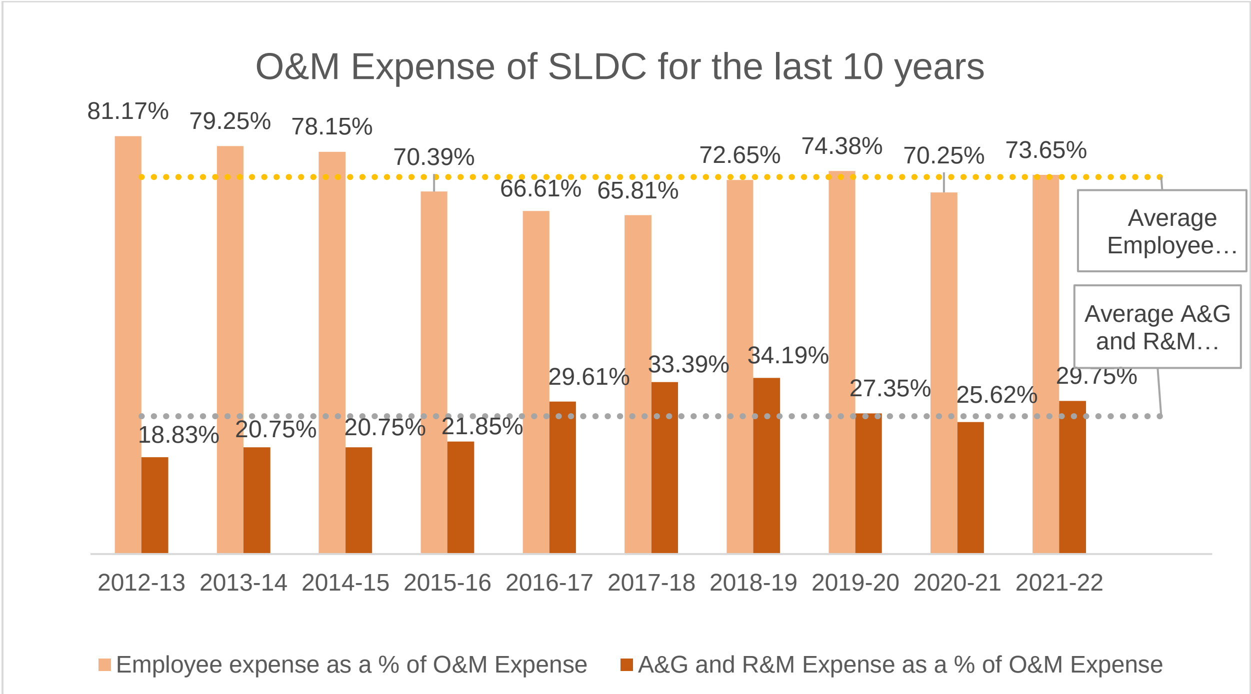
- Existing practice doesn't consider factors like- increase in no. of employees, network expansion or increase in GFA base, compliance of new age regulations to meet Standards of Performance, Rights of Consumer Rules, etc., while projecting Normative O&M expense.

- This also doesn't account for any efficiency factors to promote economic O&M practices and new technology adoption by the SLDC.

- Fixed escalation rate of 5.72%, doesn't account real time economic condition and Inflation.

Commissions' Views:

7.4.4 With regards to the determination of the weightages to be assigned to WPI and CPI index for calculation of inflation factor, it has been observed that generally the employee related expenses is linked to CPI for Industrial Workers. Whereas, nonemployee related expenses, i.e., A&G and R&M; overall WPI is a better indicator. Accordingly, the Commission has analysed the actual O&M expenses incurred by SLDC over the past years from FY 2012-13 to FY 2021-22 and has worked out the ratios, viz., employee expenses to the total O&M expenses and, A&G and R&M expenses to the total O&M expenses. The average ratio of employee expenses to the total O&M expenses across the aforesaid period has been considered as weightage of CPI and the average ratio of A&G and R&M expenses to the total O&M expenses has been considered as a weightage of WPI. The graph below shows the employee expenses as a percentage of total actual O&M expenses:



7.4.5 From the above graph, the average of actual employee expenses as a percentage of the total O&M expenses for the last 10 years will be 73.23%. Therefore, for the SLDC, an absolute value of 70% is considered as the weightage of CPI and the remaining 30% has been assigned as weightage of WPI. Hence, it is proposed to consider the weightage for CPI: WPI as 70:30 for the SLDC.

7.4.6 Accordingly, the following regulation is proposed to be included in the draft GERC MYT Regulations, 2023:

“82 Operation and Maintenance expenses

82.1 The Operation and Maintenance expenses shall be derived on the basis of the average of the actual audited Operation and Maintenance expenses for the past ten years ending March 31, 2022, excluding abnormal Operation and Maintenance expenses, if any, subject to prudence check by the Commission:

Provided that the average of such Operation and Maintenance expenses shall be considered as Operation and Maintenance expenses for the Year ended March 31, 2018, and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22 and FY 2022-23, to arrive at the Operation and Maintenance expenses for the base year ending March 31, 2023:

Provided further that the escalation rate for FY 2018-19, FY 2019-20, *FY 2020-21, FY 2021-22, and FY 2022-23, shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on the monthly Wholesale Price Index of the respective financial year as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, Government of India.*

82.2 The Operation and Maintenance expenses for nth year of the Control Period shall be determined based on the formula shown below:

O&Mn = (R&Mn + EMPn + A&Gn) x (1 - Xn) + Terminal Liabilities and other one-time expenses

Where,

R&Mn –Repair and Maintenance Costs of SLDC for the nth year;

EMPn –Employee Cost of SLDC for the nth year;

A&Gn –Administrative and General Costs of SLDC for the nth year;

Xn -Efficiency factor for nth Year. Value of Xn to be considered as zero till such time the same is determined through a study by the Commission:

Provided that the Terminal Liabilities and other one-time expenses shall be allowed separately on actual basis subject to prudence check.

82.3 It should be ensured that all such expenses capitalized should not form a part of the O&M expenses being specified here. The above components shall be computed in the manner as specified below:

*(i) R&Mn = K * GFA * (1+Index Escn)*

*(ii) EMPn+ A&Gn= (EMPn-1 + A&Gn-1) * (1+Index Escn)*

Where,

'K' is a constant (expressed in %) governing the relationship between R&M costs and Gross Fixed Assets (GFA) for the Control Period. The value of 'K' will be calculated based on the R&M expenses and GFA for past ten years (or all available years in case of utilities

operating for less than 10 years as on April 01, 2022) ending March 31, 2022 approved by the Commission, subject to prudence check and any other factor considered relevant by the Commission;

'GFA' is the Opening balance of the gross fixed assets of the nth year;

EMPn-1 - Employee Cost of SLDC for the immediately preceding year;

A&Gn-1- A&G of SLDC for the immediately preceding year;

Provided that for first year of control period EMPn-1 and A&Gn-1 shall mean Employee and A&G expenses of the year after the base year (FY 2022-23) i.e. FY 2023-24, as derived using the escalation rate for FY 2023-24 as mentioned below;

Index Esc means the average Inflation escalation to be considered on the basis of weightage of WPI and CPI respectively of the relevant year and to be computed as below:

*Index Escn = WECPI*CPIn + WEWPI*WPIn*

Whereby,

WECPI : Weightage of CPI Index and;

WEWPI: Weightage of WPI Index;

'WPIn' (expressed in %) means the average yearly inflation of Wholesale Price Index (all commodities) over the years for the nth year.

'CPIn' (expressed in %) means the average yearly inflation of Consumer Price Index (Industrial workers) over the years for the nth year.

Note: Source for CPI and WPI calculation as under:

Wholesale Price Index numbers as per Office of Economic Advisor, Ministry of Commerce & Industry, Government of India {Base Year: 2011-12 Series};

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India {Base Year: 2001=100}

Provided further that the escalation rate for FY 2023-24 and for the complete control period i.e. FY 2024-25, FY 2025-26, FY 2026-27, *FY 2027-28, and FY 2028-29 shall be computed by considering (WEWPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Consumer Price Index (CPI).*

Provided further that, in the Truing-up of the O&M expenses norms for any particular year of the Control Period, the escalation rate shall be computed by considering (WEWPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Consumer Price Index (CPI).

Note:

i. For SLDC, WECPI:WEWPI is to be considered as 70:30.

ii. O&M expenses shall be allowed on normative basis and shall be trued-up only to the account of variation in Wholesale Price Index and Consumer Price Index.

iii. The impact of Wage Revision, if any, may be considered at the time of true-up for any Year, based on documentary evidence and justification to be submitted by the Petitioner. Provisioning of wage revision expenses shall not be considered as actual expenses at the time of true-up, and only expenses as actually incurred shall be considered.

iv. Any variation in actual and normative O&M cost excluding any abnormal expenses or wage revision shall be subject to the sharing of efficiency gains or losses as per framework specified in this Regulations.

v. For the purpose of estimation, the same Index Escn value as derived for FY 2024-25 shall be used for all years of the Control Period. However, at the time of true-up of any particular year, the Commission will consider the actual values of the WPI and CPI over past ten years including True-up year.”

8 DISTRIBUTION WIRE BUSINESS

This section discusses the regulatory provisions regarding the terms and conditions for determination of tariff for Wire Business of Distribution Licensee in the State of Gujarat.

8.1 Background

8.1.1 Distribution Licensees in the State of Gujarat receive electricity at the Transmission - Distribution (T< >D) interface points through the Intra-State Transmission System. 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.

8.1.2 Section 62 of the Electricity Act, 2003 specifies that the State Commission to determine the tariff for Wheeling and Retail supply of electricity. Accordingly, for the 3rd Control period Regulation 85 and 93 of GERC MYT Regulation, 2016 specifies the regulation applicable during the third Control Period for the determination of tariff for the usage of distribution wire system and retail supply of electricity.

8.1.3 Below sections discuss the principles and methodology adopted by the Commission for determining the Aggregate Revenue Requirement and Wheeling Charges for the Distribution Wire Business for the fourth Control Period.

8.2 Component of Aggregate Revenue Requirement for Distribution Wire Business

8.2.1 The components of the Wheeling Charges for Distribution Wire Business of the Distribution Licensee has been modified in accordance with the modifications proposed in the Financial Principles in Chapter 3 of the draft Regulations.

> ***"91 Components of Aggregate Revenue Requirement for Distribution Wires Business***
>
> *91.1 Wheeling Charges for Distribution Wires Business of the Distribution Licensee shall provide for the recovery of the Aggregate Revenue Requirement for the respective years of the control period, as approved by the Commission, which shall comprise of the following:*
>
> *(a) Depreciation;*
>
> *(b) Interest and Finance Charges on Loan Capital & Return on Equity and/or Return on Capital Employed;*
>
> *(c) Interest on working capital and deposits from Distribution System Users;*

(d) Operation and maintenance expenses;

(e) Contribution to contingency reserves, if any;

(f) Income Tax;

minus:

(g) Non-Tariff Income; and

(h) Income from Other Business, to the extent specified in these Regulations:

(i) Income from Wheeling Charges payable by Distribution System Users other than the retail consumers getting electricity supply from the same Distribution Licensee.

Provided that depreciation, interest and finance charges on loan capital & return on equity and/or return on capital employed and interest on working capital and income tax for the Distribution Wires Business shall be allowed in accordance with the provisions specified in Chapter 3 of these Regulations:

…"

8.2.2 The Commission has also proposed to clarify that the prior period income/expenses shall be allowed by the Commission, only if the same has been allowed by the Commission in that prior period on actual basis. Accordingly, second proviso to Regulation 91.1 of the draft GERC MYT Regulations , 2023 has been added as follows:

"….

Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, if the income/expenses in that prior period have been allowed on actual basis, on a case to case basis, subject to prudence check.

…"

8.2.3 Further, it is to be noted that wheeling charges are being recovered from the retail consumers of DISCOMs as well as from open access consumers for usage of the distribution system and associated facilities. As the Wheeling charges from the retail consumers have already been inbuilt in the retail tariff determined by the Commission, the same is included in the revenue from retail supply of power. However, the charges recovered by the open access consumers for usage of distribution network is purely related to the Wire business and needs to be reduced from ARR of Wire Business. Hence, the Commission has proposed to modify the said provision whereby the provision which was earlier included in the Retail supply business is now incorporated in the component of tariff for Distribution Wire business.

8.2.4 Sections 57 and 58 of the Electricity Act, 2003 specified the standards of performance of a Distribution Licensee as mentioned below:

> *"Section 57. (Consumer Protection: Standards of performance of licensee): (1) The Appropriate Commission may, after consultation with the licensees and persons likely to be affected, specify standards of performance of a licensee or a class of licensees.*
>
> *(2) If a licensee fails to meet the standards specified under sub-section (1), without prejudice to any penalty which may be imposed or prosecution be initiated, he shall be liable to pay such compensation to the person affected as may be determined by the Appropriate Commission:*
>
> *Provided that before determination of compensation, the concerned licensee shall be given a reasonable opportunity of being heard.*
>
> *(3) The compensation determined under sub-section (2) shall be paid by the concerned licensee within ninety days of such determination.*
>
> *Section 58. (Different standards of performance by licensee):*
>
> *The Appropriate Commission may specify different standards under subsection (1) of section 57 for a class or classes of licensee."*

8.2.5 Under the above mentioned Sections of Act, the Licensees are liable for the payment of compensation to the affected person for failing to meet the specified standards. These compensation/penalties may be determined by the appropriate Commission for a licensee.

8.2.6 Also, Section 161 of the Electricity Act, 2003 provides for notice of accidents and inquiries, wherein if any accident occurs in connection with the distribution, supply or use of electricity in or in connection with, any part of the electric lines or electrical plant of any person and the accident results or is likely to have resulted in loss of human or animal life or in any injury to a human being or an animal, such person shall give notice of the occurrence and of any such loss or injury actually caused by the accident, in such form and within such time as may be prescribed, to the Electrical Inspector or such other person as aforesaid and to such other authorities as the Appropriate Government may by general or special order, direct. However, no provision was made for payment of any compensation to any person affected. Apart from above, Distribution Licensee may also be liable to penalties/compensations due to orders of the Commission.

8.2.7 In order to safeguard the interest of a consumer, the Commission is of the view that such penalties/compensations raised due to inefficiency and failure of the licensee should not be recovered from the consumer. Moreover, for the proper treatment of paid penalties/compensation during Truing-up of ARR, Licensee should maintain a separate record for such payment of penalties/compensation and same has to be submitted to the Commission along with the truing-up petition.

8.2.8 Considering the above aspects, following provisos are proposed to be added in the draft GERC MYT Regulations , 2023:

"…..

Provided also that all penalties and compensation payable by the Licensee to any party for failure to meet any Standards of Performance or for damages, as a consequence of the Orders of the Commission shall not be allowed to be recovered through the Aggregate Revenue Requirement: whereby the details of penalties and compensation paid or payable, if any, is required to be submitted to the Commission along with the Petition under these Regulations:

Provided also that 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 Chapter 2 of these Regulations:"

8.2.9 With regard to the voltage-wise determination of wheeling charges, it is proposed to add following provisos for the clarity in philosophy of determination of wheeling charges:

"….

Provided also that the Wheeling Charges may be denominated in terms of Rupees/kWh or Rupees/kVAh or Rupees/kW/month or Rupees/kVA/month, for the purpose of recovery from the Distribution System User, or any such denomination, as stipulated by the Commission from time to time.

Provided further that the Wheeling Charges shall be determined separately for LT voltage, HT voltage, and EHT voltage, as applicable:

Provided also that in case of a Deemed Distribution Licensee whose tariff is yet to be determined by the Commission till the date of coming into of these Regulations, the Commission may determine the ceiling Wheeling Charges that may be charged by such Deemed Distribution Licensee till such time as considered appropriate by the Commission."

8.3 Operation and Maintenance expenses:

8.3.1 Regulation 86.2 of the MYT Regulations, 2016 specifies the principle for computation of Operation and Maintenance (O&M) expenses for Distribution Wire Business, wherein the O&M expenses were derived on the basis of the average of the actual O&M expenses for the three (3) years ending March 31, 2015, which was considered as O&M expenses for FY 2013-14. Thereafter, the base O&M expenses were escalated by 5.72% per annum to arrive at the O&M expenses for the respective years in the Control Period. At the time of truing-up, the Commission allows normative O&M expenses as per the provisions of the GERC MYT Regulations and allows the sharing of efficiency gains or losses as per the variation in normative O&M Expenses vis-à-vis actual O&M Expenses incurred by Distribution Licensee after prudence check.

8.3.2 The Discussion Paper has highlighted the following issues with the existing approach of computing normative O&M expenses:

- Existing practice doesn't consider factor like- increase in no. of employees, network expansion or increase in GFA base, compliance of new age regulations to meet Standards of Performance, Rights of Consumer Rules, etc., while projecting Normative O&M expense.
- This also doesn't account for any efficiency factors to promote economic O&M practices and new technology adoption by the Distribution Licensee.
- Fixed escalation rate of 5.72%, doesn't account real time economic condition and Inflation.

8.3.3 In view of above, the Discussion Paper proposed the following formula to compute O&M expenses for the nth year of the Control Period:

"O&Mn = (R&Mn + EMPn + A&Gn) x (1 - Xn) + Terminal Liabilities and other one-time expenses

Where,

R&Mn = K x GFAn-1 x (Indxn / Indxn-1)

EMPn = (EMPn-1) x (1+Gn) x (Indxn / Indxn-1)

A&Gn = (A&Gn-1) x (Indxn / Indxn-1)

'K' is a constant (expressed in %). Value of K for each Year of the Control Period shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking of repair and maintenance expenses, approved repair and maintenance expenses vis-à-vis GFA approved by the Commission in past and any other factor considered appropriate by the Commission;

INDXn – Inflation factor to be used for indexing may be a combination of the Consumer Price Index (CPI) and the Wholesale Price Index (WPI) for *immediately preceding year before the base year;*

EMPn – Employee expenses of the Distribution Licensee for the nth Year;

A&Gn – Administrative and General expenses of the Distribution Licensee for the nth Year;

R&Mn – Repair and Maintenance expenses of the Distribution Licensee for the nth Year;

GFAn-1 – Gross Fixed Asset of the Distribution Licensee for the n-1th Year;

Gn is a growth factor for the nth Year. Value of Gn shall be determined by the Commission in the MYT tariff order for meeting the additional manpower requirement based on Licensee's filings, benchmarking, approved cost by the Commission in past and any other factor that the Commission feels appropriate.

Xn is an efficiency factor for nth Year. Value of Xn shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking, approved cost by the Commission in past and any other factor the Commission feels appropriate;

…"

8.3.4 Stakeholders' comments on the O&M expenses and related matter has been summarized as follows:

Escalation Factor:

8.3.5 Adani Power has submitted that moving average of WPI & CPI may be considered equivalent to the number of years for the control period so as the expenses reflects the actual escalation during the corresponding period.

8.3.6 MUL has submitted that instead of considering average of last 8 to 10 years' WPI and CPI, average of last 3 years' WPI and CPI applied shall be considered for projections. Further, for the Truing-up of O&M Expense, escalation factor shall be considered on actuals.

8.3.7 GUVNL has submitted that that as per the last four years details of O & M Expenses the actual overall escalation for State owned Distribution Companies is around 12% per annum (excluding exceptional increase in employee cost due to pay revision). Thus, the growth factor and escalation factor need to be considered in a manner which captures increase in O & M expenses in realistic manner, at least at 12% per annum.

8.3.8 TPL has submitted that 8- 10 years moving average of WPI & CPI for deriving

Escalation Factor (indxn) is not reflective of current market conditions. Therefore, it is suggested to consider 3-Years Average of WPI & CPI for Escalation Factor for projection of O&M Expense subject to adjustment of actual WPI & CPI.

Projection of O&M expenses:

8.3.9 GUVNL has submitted that the distribution business is continuously expanding in nature and hence requirement of R&M expense, Employee expense and A&G expense is continuously increasing along with expansion of network, increase in number of consumers and quantum of supply over and above inflationary increase of existing expenses. As per formula proposed in the discussion paper increase in R&M is sought to be linked with increase in Gross Fixed Asset by allowing escalation with constant 'K". Similarly, in respect of Employee expenses, the definition of Growth Factor (Gn). Whereas for A&G expenses, only inflationary increase is provided without providing any escalation due to increase in distribution network, sales quantum and consumer base. GUVNL also submitted that with increase in number of consumers and quantum of sales, there is requirement to increase administrative set up .Thus, A&G expenses along with R & M expenses and Employee expenses need to be compensated correspondingly.

8.3.10 TPL has submitted that A&G Expense also depends on Business Growth. Thus, there is a need to factor necessary consideration of business growth in the formula of A&G Expenses. It has also stated that the ‘K’ Factor shall be well defined in the regulations, so as to avoid ambiguity in this matter. Further, it has highlighted that Discussion Paper proposes separate approval process for legal/litigation expenses and also seeks documentary evidence, which amounts to micromanagement of utility’s expenditure. It has also stated that Legal expenses are part and parcel of any business and are depend upon the complexity of business and its impact on the Utility.

8.3.11 MUL has submitted that assets are being built by consumers/developers by its own cost and is being handed over to the Distribution Licensee to maintain the same and hence it should be added while calculating R&M expenses. Further, it has submitted that any type of one-time expenses (such as Example one time IT infra cost, registration cost, statutory and legal charges, consultancy charges, advertisement cost, Petition Fees etc.) incurred shall be allowed separately under O&M expense.

8.3.12 FOKIA submitted that smart meter would increase the O&M expense of distribution licensee. The additional O&M expense should be met from the gain of improvement in metering efficiency, billing efficiency and Revenue efficiency due to providing smart meters. Further it has stated that, if there is any shortfall in expense and gains, the same shall not be passed on to the consumers.

Efficiency Factor:

8.3.13 MUL has submitted that initially, the efficiency factor, Xn may be considered as Nil. Same may subsequently be determined based on a separate detailed study at the time of mid-term review of the MYT Control Period.

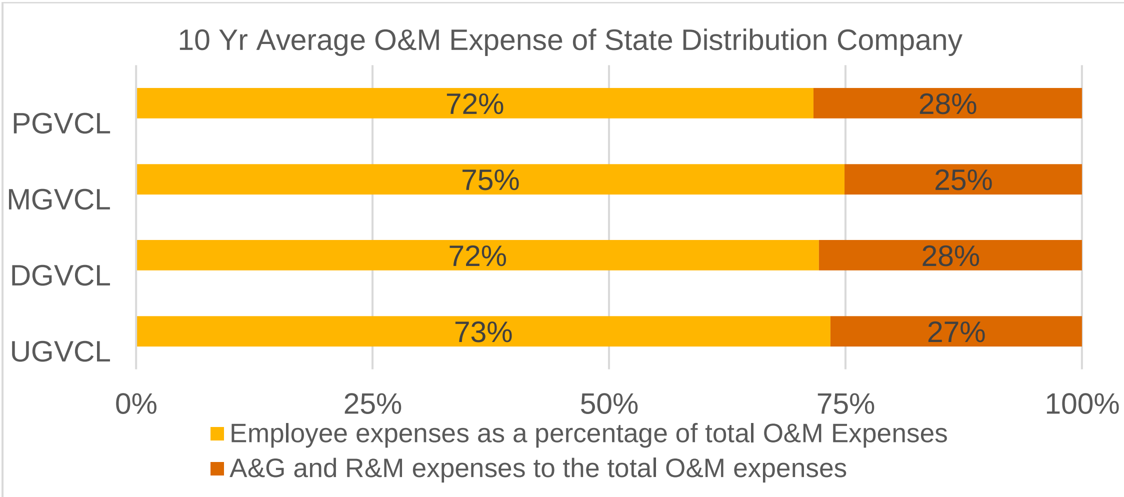
8.3.14 GUVNL has submitted that increase O&M expenses are considered as controllable factor and required to be borne by distribution licensee under the sharing mechanism. Therefore, reducing the O&M expenses with efficiency factor will lead to double implication for distribution licensee for the same parameter, namely implication under sharing mechanism and implication of reduction in O&M expenses due to consideration of efficiency factor in the O&M expenses formula. Therefore, the formula for determination of O&M expenses need to be corrected.

8.3.15 TPL has submitted that O&M Expense should not be reduced by applying Efficiency Factor, as increase in O&M expenses is imperative on account of inflation and stringent norms /performance parameters introduced under the MoP Rules on Consumer rights.

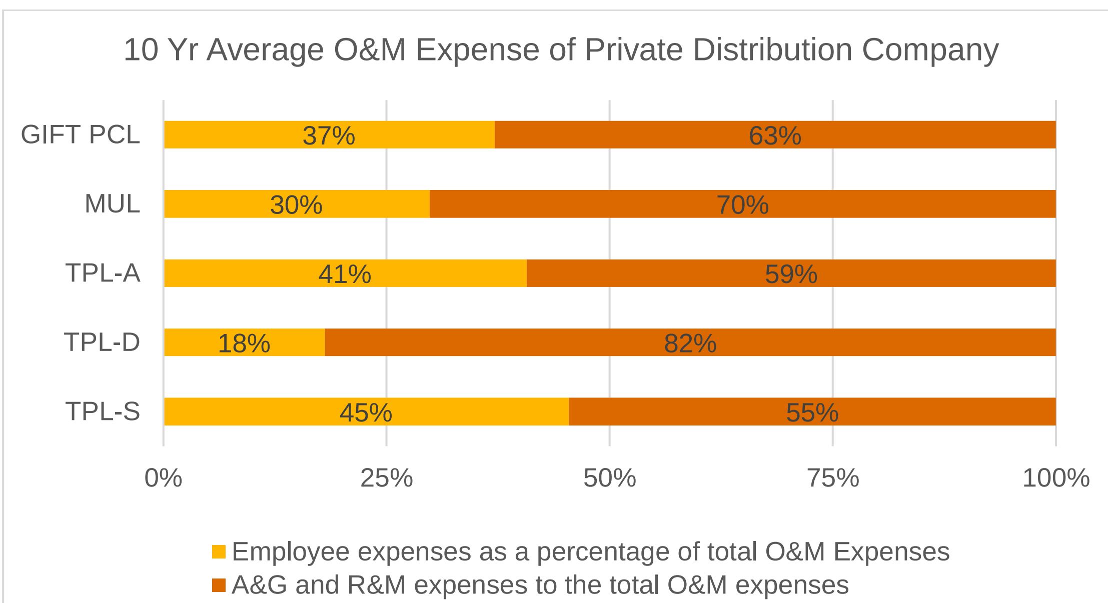
Commissions' Views:

8.3.16 The Commission has considered the suggestion from the stakeholders. As highlighted in the Discussion Paper that fixed escalation does not apprehend the real inflation over the year. It also doesn't recognize growth in assets base of a distribution utility. Hence, to address the said issue the Commission has proposed to adopt the WPI: CPI indexation mechanism as explained in earlier section of this memorandum.

8.3.17 In regards to the determination of the weightages to be assigned to WPI and CPI index for calculation of inflation factor, the Commission has analysed the actual O&M expense of last 10 year (i.e. from FY 2012-13 to FY 2021-22) of DISCOMs. The employee expenses to the total O&M expenses and A&G and R&M expenses to the total O&M expenses ratios have been workout for the determination of CPI and WPI weightage respectively as shown in graph below:



8.3.18 The average of actual employee expenses as percentage of the total O&M expenses of state distribution licensee for the last 10 years is works out in range of 72- 75% as shown in the above graph. Therefore, for the State Discoms, an absolute value of 75% is considered as the weightage of CPI. Accordingly, the remaining 25% has been assigned as weightage of WPI. Hence, it is proposed to consider the weightage for CPI: WPI is considered as 75:25 for State Distribution Licensee.



8.3.19 With respect to private sector and small Distribution Licensees (other than State Discoms), it was observed that the average for the last 10-years employee expenses as a percentage of O&M expenses is in the range from 18% to 45%. Further, some of the small Distribution Licensees are still under developing stage. Hence, for determination of the weightage for the CPI for private Distribution Company and SEZ, the Commission has relied on data associated with more matured Distribution Licensees, i.e., TPL (Ahmedabad) and TPL (Surat). The average of employee expenses as a percentage of O&M expenses for TPL (Ahmedabad) and TPL (Surat) for the period from FY 2012-13 to FY 2021-22, works out around 43%. Accordingly, the weightage of CPI for private sector and small Distribution Licensees is proposed to be considered as 45%. The remaining part, i.e., 55% is then assigned to WPI. Hence, it is proposed to consider the CPI:WPI as 45:55 for State Distribution Licensee.

8.3.20 Further, WPI for the year is to be considered based on the average yearly inflation derived based on the monthly Wholesale Price Index of the respective past 10 financial years as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and CPI is to be considered based on the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective past 10 financial years as per the Labour Bureau, Government of India.

8.3.21 Accordingly, the following regulation is proposed to be included in the draft GERC MYT Regulations, 2023:

"92 Operation and Maintenance expenses:

92.1 Operation and Maintenance shall be derived on the basis of the average of the actual audited Operation and Maintenance expenses for the past ten years ending March 31, 2022, excluding abnormal Operation and Maintenance expenses, if any, subject to prudence check by the Commission:

Provided that the average of such Operation and Maintenance expenses shall be considered as Operation and Maintenance expenses for the Year ended March 31, 2018, and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22 and FY 2022-23, to arrive at the Operation and Maintenance expenses for the base year ending March 31, 2023;

Provided further that the escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22 and FY 2022-23 shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on the monthly Wholesale Price Index of the respective financial year as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on the monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, *Government of India.*

92.2 Operation and Maintenance expenses for nth year of the Control Period shall be determined based on the formula shown below:

O&Mn = (R&Mn + EMPn + A&Gn) x (1 - Xn) + Terminal Liabilities and other one-time expenses

Where,

R&Mn –Repair and Maintenance Costs of Distribution Wire Business for the nth year;

EMPn –Employee Cost of Distribution Wire Business for the nth year;

A&Gn –Administrative and General Costs of Distribution Wire Business for the nth year;

Xn -Efficiency factor for nth Year. Value of Xn to be considered as zero till such time the same is determined through a study by the Commission.

Provided that the Terminal Liabilities and other one-time expenses shall be allowed separately on actual basis subject to prudence check.

92.3 It should be ensured that all such expenses capitalized should not form a part of the O&M expenses being specified here. The above components shall be computed in the manner as specified below:

*(i) R&Mn = K * GFA * (1+Index Escn)*

*(ii) EMPn+ A&Gn= (EMPn-1 + A&Gn-1) * (1+Index Escn)*

Where,

'K' is a constant (expressed in %) governing the relationship between R&M costs and Gross Fixed Assets (GFA) for the Control Period. The value of 'K' will be calculated based on the R&M expenses and GFA for past ten years (or all available years in case of utilities operating for less than 10 years as on April 01, 2022) ending March 31, 2022 approved by the Commission, subject to prudence check and any other factor considered relevant by the Commission;

'GFA' is the Opening balance of the gross fixed assets of the nth year;

EMPn-1 - Employee Cost of Distribution Wire Business for the immediately preceding year;

A&Gn-1- A&G of Distribution Wire Business for the immediately preceding *year;*

Provided that for first year of control period EMPn-1 and A&Gn-1 shall mean Employee and A&G expenses of the year after the base year (FY 2022-23) i.e. FY 2023-24, as derived using the escalation rate for FY 2023-24 as mentioned below;

Index Esc means the average Inflation escalation to be considered on the basis of weightage of WPI and CPI respectively of the relevant year and to be computed as below:

Index Escn = WE_{CPI}**CPIn +* WE_{WPI}**WPIn*

Whereby,

WECPI : Weightage of CPI Index and;

WEWPI: Weightage of WPI Index;

'WPIn' (expressed in %) means the average yearly inflation of Wholesale Price Index (all commodities) over the years for the nth year.

'CPIn' (expressed in %) means the average yearly inflation of Consumer Price Index (Industrial workers) over the years for the nth year.

Note: Source for CPI and WPI calculation as under:

Wholesale Price Index numbers as per Office of Economic Advisor, Ministry of Commerce & Industry, Government of India {Base Year: 2011-12 Series};

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India {Base Year: 2001=100}

Provided further that the escalation rate for FY 2023-24 and for the complete control period i.e. FY 2024-25, FY 2025-26, FY 2026-27, FY 2027-28, and FY 2028-29 shall be computed by considering (WE_{WPI}*) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Wholesale Price Index (WPI) and (*WE_{CPI}*) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Consumer Price Index (CPI):*

Provided further that, in the Truing-up of the O&M expenses norms for any particular year of the Control Period, the escalation rate shall be computed by considering (WE_{WPI}*) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Wholesale Price Index (WPI) and (*WE_{CPI}*) weightage to the 10-year moving average of* *the yearly inflation of the last ten years including the true-up year for Consumer Price Index (CPI).*

Note:-

(a) For state government owned Distribution Licensees, Distribution Wire Business WECPI:WEWPI is to be considered as 75:25.

(b) For Other Distribution Wire Business WECPI:WEWPI is to be considered as 45:55.

(c) O&M expenses shall be allowed on normative basis and shall be trued-up only to the account of variation in Wholesale Price Index and Consumer Price Index.

(d) The impact of Wage Revision, if any, may be considered at the time of true-up for any Year, based on documentary evidence and justification to be submitted by the Petitioner. Provisioning of wage revision expenses shall not be considered as actual expenses at the time of true-up, and only expenses as actually incurred shall be considered.

(e) Any variation in actual and normative O&M cost excluding any abnormal expenses or wage revision shall be subject to the sharing of efficiency gains or losses as per framework specified in this Regulations.

(f) In the case of a Deemed Distribution Licensee whose tariff is yet to be determined by the Commission till the coming into force of these Regulations, the Commission may determine the Operation and Maintenance expenses on a case to case basis.

(g) For the purpose of estimation, the same Index Escn value as derived for FY 2024-25 shall be used for all years of the Control Period. However, at the time of true-up of any particular year, the Commission will consider the actual values of the WPI and CPI over past ten years including True-up year."

8.4 Contribution to contingency reserves

8.4.1 Regulation 86.3 of GERC MYT Regulation, 2016 specifies that utility shall contribute a sum not exceeding 0.5 per cent of the original cost of fixed assets in contingency reserve and the same shall be allowed as part of Aggregate Revenue Requirement. Further, contribution in Contingency Reserve beyond five (5) per cent of the original cost of fixed assets shall not be allowed as ARR. The relevant regulation of GERC MYT Regulation, 2016 is reproduced as below:

"86.3 Contribution to contingency reserves:

86.3.1 The Distribution Licensee may make an appropriation to the Contingency Reserve of a sum not exceeding 0.5 per cent of the original cost of fixed assets at the beginning of the year, for each year, which shall be allowed in the calculation of aggregate revenue requirement:

Provided that where the amount of such Contingency Reserve 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 may be invested in securities authorised under the Indian Trusts Act, 1882 or any other security within a period of six months of the close of the financial year:

Provided also that if the amount so appropriated is invested in securities, then the actual interest income earned by the Distribution Licensee shall be included under the Non-Tariff income:

Provided also that if the amount so appropriated is not invested in securities, then the normative interest income, computed at the weighted average State Bank Base Rate for the year, shall be included under the Non-Tariff income of the Distribution Licensee.

"86.3.2 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, natural calamities or circumstances which the management could not have prevented;

(b) Expenses on replacement or removal of plant or works other than expenses required 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 and Government Grant, if any.

No diminution in the value of contingency reserve as mentioned above shall be allowed to be adjusted as a part of tariff."

Suggestion/Comment from Stakeholders:

8.4.2 GUVNL submits that submitted that the state of Gujarat is prone to frequent natural calamities such as floods, torrential rains, cyclones etc. damaging Transmission & Distribution infrastructure. Further, utilities are required to incur huge expenses for network restoration work for recommencement of power supply in timely manner. Therefore, it would be appropriate to provide for creation of 'contingency reserve fund' by utilities to mitigate exigencies arising out of natural calamities.

Commissions View:

8.4.3 The concept of creation of Contingency Reserve is to ensure availability of emergency fund, without approaching consumers for allowance of the expenses. It is for this reason that the existing regulations specify that the amount of Contingency Reserve shall be invested in specified securities, and also specify the manner and heads on which the Contingency Reserve may be utilised. Thus, there is a need of proper monitoring of contingency reserve so as to avoid mishandling of such fund. Accordingly, it is proposed to continue with the existing provisions in this regard with slight modifications:

"93 Contribution to contingency reserves:

93.1 Distribution Licensee may make an appropriation to the Contingency Reserve of a sum not exceeding 0.5 per cent of the original cost of fixed assets at the beginning of the year, for each year, which shall be allowed in the calculation of aggregate revenue requirement:

Provided that where the amount of such Contingency Reserve 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 that Distribution Licensees shall maintain separate accounts in their books and reflect the balance in the Contingency Reserve Account in the balance sheet.

Provided that the fund under Contingency Reserve shall be kept in a separate bank account and the amount so appropriated may be invested in securities authorised under the Indian Trusts Act, 1882 or any other security within a period of six months of the close of the financial year whereby the investment is required to be restricted to interest bearing securities only preferably government securities and shall not be a market linked products:

Provided also that if the amount so appropriated is invested in securities, *then the actual interest income earned by Distribution Licensee shall be included under the Non-Tariff income:*

Provided also that if the amount so appropriated is not invested in securities, then the normative interest income, computed at one year SBI MCLR or any replacement thereof declared by SBI from time to time being in effect applicable for 1 year period, as applicable for the year, shall be included under the Non-Tariff income of the Distribution Licensee.

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

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

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

93.3 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 and Government Grant, if any.

93.4 No diminution in the value of contingency reserve as mentioned above shall be allowed to be adjusted as a part of tariff. "

8.5 Segregation Accounts of Distribution Licensee

8.5.1 Regulation 87 of GERC MYT Regulation, 2016 specifies the allocation matrix for segregation of expenses between Distribution Wires Business and Retail Supply Business, in case the separate accounts are not available. It is necessary to have an allocation matrix for apportioning the ARR of the distribution business between the Wires business and Supply business. Relevant extract of GERC MYT Regulation, 2016 is as follows:

*"**87. Allocation Matrix***

The Wheeling Charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business:

Provided that where the Distribution Licensee is not able to submit audited *and certified separate accounts for Distribution Wires Business and Retail Supply Business, the following Allocation Matrix shall be applicable:*

Table 15: Allocation matrix for segregation of expenses between Distribution Wires Business and Retail Supply Business

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

Provided further that the operation and maintenance expenses shall be allocated between the Distribution Wires Business and Retail Supply Business, by considering the above-specified percentages for employee expenses, administration and general expenses, and repair and maintenance expenses, as weights for determining the weighted average allocation percentage for operation and maintenance expenses:

Provided also that once the Commission notifies the Regulations for submission of Regulatory Accounts, the wheeling charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business."

8.5.2 The Discussion Paper highlighted that despite the continued emphasis of the Commission on separation of the accounting of wires related costs and supply related costs, there is little or no initiative by the Distribution Licensees for segregation of expenses between the Wire Business and Retail Supply Business. The segregation is required to move towards greater competition in the retail supply business, as well as determination of true wheeling charges,. Subsequently it was proposed to continue with an 'Allocation Matrix' for the new Control Period, with following action plan for segregation of account of distribution licensee:

a) Commission to issue guidelines for segregation of accounts of Distribution Licensee between Wires Business and Retail Supply Business in next 6 months;

b) Distribution Licensees to undertake the preparatory work for segregate their accounts of Wires Business and Retail Supply Business in next 6 months;

c) Distribution Licensees to submit their respective audited and certified separate accounts for Distribution Wires Business and Retail Supply Business from the next financial year onwards, i.e. year 2 of the new MYT Control Period, which shall become the basis for determination of wheeling and retail supply ARRs and hence the determination of wheeling charges;

d) Distribution Licensees not able to provide audited and certified separate accounts for Distribution Wires Business and Retail Supply Business, shall continue to segregate the expenses of Distribution Business based on the 'Allocation Matrix' provided in the MYT Regulations. However, in such case, the rate of return on Equity shall be reduced to the base rate / reduced by 1.00% from the normal rate of return of Equity.

Suggestion/Comment from Stakeholders:

8.5.3 MUL submitted that Allocation Matrix for segregation of expenses should be retained otherwise it will be a tough task for segregation of expenses between the Wire Business and Retail Supply Business of the Distribution Licensee.

8.5.4 GUVNL has requested the Commission to provide reasonable time period of at least 6 months to DISCOMs for preparation of segregated accounts after notification of guidelines and provide an opportunity to DISCOMs for filing of comments / suggestions before finalising the guidelines. Further, GUNVL has submitted that the segregation between Wires Business and Retail Supply Business based on Allocation matrix till the time accounts are segregated it is respectfully submitted that all expenses of distribution companies except power purchase cost, is related to wire business only as power is wheeled either for supply to consumers or for wheeling to third party. Therefore, ARR for wire business are to be worked out considering all expenses excluding power purchase cost and not based on the allocation matrix proposed in the regulations.

8.5.5 TPL has submitted that Wire and Supply Business are not recognized as a separate license business in the Act. Further, it has also stated that Expenses are interwoven and watertight segregation between Wires and Supply is not desirable as same leads to increase in cost. Accordingly, it has proposed that Distribution Licensee should not be asked for separation of Accounts when it is the part of one license. Since, any proposal to segregate and maintain Wires and Supply as separate business is contrary to the Act. Further, it has also submitted that any proposal of reducing RoE, if Discoms are unable to submit separate accounts is uncalled for and also not tenable under the law.

Commissions View:

8.5.6 The Commission has considered the submission of all stakeholders. Based on above discussion, the Commission is of the view to continue with the prevailing allocation ratio as specified in GERC MYT Regulation, 2016 in case if Distribution Licensee is not able to submit audited and certified separate accounts for Distribution Wires Business and Retail Supply Business.

8.5.7 Further, the Commission would like to propose timeline for segregation of accounts of wires related costs and supply related costs, along with the penalty for missing proposed timeline as per the discussion in Section 4.5. Accordingly, following Regulations is proposed in the draft GERC MYT Regulations, 2023:

"94 Allocation Matrix

94.1 The Wheeling Charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business. Every Distribution Licensee shall maintain segregated accounting records for the Distribution Wires Business and Retail Supply Business by the third year of Control Period.

Provided that Distribution Licensee shall be penalised as per Regulation 35.12 of these Regulations, in case it fails to maintain separate books of accounts for the Distribution Wire Business and Retail Supply Business from the third year of Control Period.

Provided further that the guidelines specified by the Commission as per Annexure V to these Regulations to be followed

Provided further that in case complete accounting segregation has not been done between the Wheeling Business and Retail Supply Business, the Aggregate Revenue Requirement of the Distribution Licensee shall be apportioned between Wheeling Business and Retail Supply Business in accordance with the Allocation Matrix specified as follows:

Table 12: Allocation matrix for segregation of expenses between Distribution Wires Business and Retail Supply Business

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

Provided further that the Operation and Maintenance expenses shall be allocated between the Distribution Wires Business and Retail Supply Business, by considering the above-specified percentages for employee expenses, administration and general expenses, and repair and maintenance expenses, as weights for determining the weighted average allocation percentage for operation and maintenance expenses:

Provided that any sub-component of the above heads, if is directly attributable to Wire or Supply business, then the same needs to be allocated based on the nature of such Cost / Income."

8.6 Capital investment Plan

8.6.1 Regulation 88 of GERC MYT Regulations, 2016 provide for submission of detailed Capital Investment Plan by the Utilities as a part of MYT Petition, with a view to further regularize and streamline the filing and approval process of Capital Investment Schemes, a need is felt for developing a comprehensive Capital Investment Plan approval process, covering various aspects including threshold limit for prior approval, process of submission for approval, details required for prudence check, defining framework for approval of Schemes, need for approval of completed cost, etc. Relevant regulation of GERC MYT Regulation, 2016 specifies as follows:

"88. Capital Investment Plan

88.1 The Distribution Licensee shall submit detailed capital investment plan, financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, reduction in distribution losses, improvement in quality of supply, reliability, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.

88.2 The Distribution Licensee shall be required to ensure optimum investments to enhance efficiency, productivity and meet performance standards prescribed by the Commission."

8.6.2 Ministry of Power, Government of India has published draft Electricity (Amendment) Rules, 2023 incorporating provisions of 'subsidy accounting & payment' and 'Framework for financial sustainability' for comments. The relevant extract of the draft Rule 20 is reproduced as follows:

"20 (I) Framework for financial Sustainability:

….

(d) All the prudent cost incurred by the Distribution licensee for creating the assets for development and maintenance of distribution system in accordance with sub-section (1) of section 42 of the Act shall be pass-through;

Provided that such pass-through of the cost for the assets created by the distribution licensee shall be subject to following conditions:

i) Asset has been created in accordance with the capex roll out plan for the licensee approved by the respective State Commission.

ii) Asset has been procured in competitive and transparent manner.

iii) Asset are geo-tagged and properly recorded in Fixed Asset Register (FAR) and the details are made available on the website of the Distribution licensee.

…"

8.6.3 Capital Investment scheme has a significant impact on the overall costs, and hence the revenue requirement and tariff determination process for regulated entities. Further, it is to be noted that distribution wire business is capital intensive business as they provideinfrastructure for conveyance of electricity and to meet the demand of the end consumers. The need for regulating the Capital Investment Schemes in an unambiguous and transparent manner is critical for providing regulatory certainty, for promoting efficient and optimal utilization of resources. Accordingly, the Discussion Paper had also proposed to develop a comprehensive Capital Investment Scheme approval framework for the utilities in the State of Gujarat, including following key aspects:

- Categorization of Capital Investment Schemes for Generation, Transmission, SLDC and Distribution Utilities.
- Threshold limits for in-principle prior approval separately for Generation, Transmission, SLDC and Distribution Utilities (including those for Parallel License situations).
- Categorization of Schemes not requiring prior-approval from the Commission, including overall monetary limits for as a percentage of total capital investment, etc.
- Process for submission of application for in-principle prior approval – content of application, Detailed Project Report, etc.
- Details required for prudence check - Technical and Financial criteria for in-principle approval of schemes, cost-benefit analysis, utilisation index of the assets, etc. for final approval of completed cost.
- Approval process – In principle, final approval along with ARR and tariff determination and final approval of the completed cost including conditions to be fulfilled for allowing capitalization including geo-tagging, reflection in Fixed Asset Register, etc.
- Other conditions including – Capital Investment Schemes not approved by the Commission, not to be allowed in the ARR, enabling provisions for operationalization of the proposed capital investment approval framework as a continuous process independent of the annual or periodical ARR / MYT Petitions filing process.

Suggestion/Comment from Stakeholders:

8.6.4 Prayas Energy Group submits that regulations should also have public processes for in-principal approval of capex schemes, clear frameworks specified for post-facto cost-benefit analysis at the time of DPR submission as well as a web-based portal with details on delays, cost-overruns and capital works in progress for DPR and non-DPR schemes. The scrutiny and approval process should be relevant for all capex projects.

Commissions Views:

8.6.5 For meeting the requirement of demand growth, reduction in distribution losses, improvement in quality of supply, reliability, metering, reduction in congestion, and technological advancement etc., it is likely that Distribution Licensee would need to undertake extensive capital investment for development of new infrastructure and for strengthening/augmentation of existing distribution network. Hence, the Commission, is of the view that there is a need of a capital investment plan to be submitted by Distribution Licensee at the time of MYT Petition, so as to assess the need and impact of the same on the tariff. The Commission has also observed that distribution system infrastructure of some of Distribution Licensees also include system at EHT voltage level and/ or beyond threshold limit of Rs. 100 Crores, which is also proposed to be covered under TBCB mechanism under Section 63 of the Act, similar to that of InSTS Projects. Further, the Commission is of the view that proposed guideline will ensure that the proposed capital investment schemes are necessary and do not impose an unnecessary burden on consumers by way of tariff. Accordingly, the Commission proposes the following regulation in the draft Regulation:

"95 Capital Investment Plan

95.1 Distribution Licensee shall submit detailed capital investment plan, financing plan and physical targets for each year of the Control Period for strengthening and augmentation of distribution network, meeting the requirement of load growth, reduction in distribution losses, improvement in quality of supply, reliability, metering, reduction in congestion, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.

Provided that all new and augmentation capital investment projects of 220 kV & above voltage level (including associated equipment of downstream voltage level) or having estimated cost excluding land cost of more than 100 Crores, being part of the Distribution Licensee's Capital Investment Plan, shall be implemented through Tariff Based Competitive Bidding (TBCB) in accordance with the guidelines issued under Section 63 of the Act and any deviation from the guidelines should have prior approval of the Commission. The tariff of such Distribution projects shall be discovered under Section 63 of the Act.

Provided further that the Distribution Licensee shall follow guidelines prepared by STU for InSTS projects covered under TBCB under these Regulations, till separate *guidelines are framed by the Commission in this regard*

95.2 Distribution Licensee shall be required to ensure optimum investments to enhance efficiency, productivity and meet performance standards prescribed by the Commission.

95.3 Distribution Licensee shall be required to ensure that the procurement of the assets have been undertaken in a competitive and transparent manner. Further the assets so capitalized as a part of the approved capital investment plan under these Regulations should necessarily be geo-tagged and properly recorded in Fixed Asset Register (FAR) for allowance of the capitalization of the same by the Commission.

Provided that regarding the Assets already capitalized as on April 01, 2024, the Distribution Licensee shall prepare and submit to the Commission a time-bound plan to undertake the geo-tagging in phased manner, preferably within the Control Period, along with the MYT Petition.

Provided further that the Distribution Licensee must provide access of the details of geo-tagging to the Commission for online monitoring.

95.4 Capital Investment in network expansion in distribution shall be based on load flow studies and in accordance with the requirements of the State Grid Code.

95.5 Distribution licensee shall submit the Capital Investment Plan as specified in Chapter 2 of these Regulations.

95.6 Capital Investment Plan shall be a least cost plan for undertaking investments and shall cover all capital expenditure projects of a value as specified in Guidelines for in-principle clearance of proposed investment schemes as provided in Annexure III of these Regulations or such other amount as may be stipulated by the Commission from time to time, and shall be in such form as may be stipulated.

95.7 Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required showing the need for the proposed investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the wheeling charges of the Distribution Wire Business.

95.8 The Commission shall consider the Capital Investment Plan along with the Aggregate Revenue Requirement for the entire Control Period submitted by the Distribution Wire Business taking into consideration the prudence of the proposed expenditure and estimated impact on the wheeling charges of the Distribution Wire Business.

95.9 Capital investment plan shall incorporate list of schemes in order of priority so as to enable the Commission to approve the schemes in that order and in case lesser amount of capital expenditure is to be approved then the schemes of lower priority could be disapproved.

95.10 Distribution Wire Business shall submit, along with the Petition for determination of Aggregate Revenue Requirement on each year of the control period, details showing the progress of capital expenditure projects, together with such other information, particulars or documents as the Commission may require to assess such progress."

8.7 Non Tariff Income

8.7.1 Regulation 97 of GERC MYT Regulation, 2016 specifies the Non-Tariff Income relating to the Retail Supply of electricity as below:

" 89. Non-Tariff Income

89.1 The amount of Non-Tariff Income relating to the Distribution Wires Business as approved by the Commission shall be deducted from the Aggregate Revenue Requirement in determining the wheeling charges of Distribution Wires Business of the Distribution Licensee:

Provided that the Distribution Licensee shall submit full details of its forecast of Non-Tariff Income to the Commission along with its application for determination of wheeling charges.

89.2 The indicative list of various heads to be considered for Non-Tariff Income shall be as under:

a) Income from rent of land or buildings;

b) Income from sale of scrap;

c) Income from statutory investments;

d) Income from interest on contingency reserve investment;

e) Interest on advances to suppliers/contractors;

f) Rental from staff quarters;

g) Rental from contractors;

h) Income from hire charges from contactors and others;

i) Income from advertisements, etc.;

j) Miscellaneous receipts;

k) Interest on advances to suppliers;

l) Excess found on physical verification;

m) Deferred Income from grant, subsidy, etc., as per Annual Accounts;

n) Prior period income, etc.:

Provided that the interest/dividend earned from investments made out of Return on Equity corresponding to the Distribution Wires Business of the Distribution Licensee shall not be included in Non-Tariff Income."

8.7.2 Accordingly, the following draft Regulation is proposed with minor modification in the draft regulations:

"96 Non-Tariff Income

96.1 The amount of Non-Tariff Income relating to the Distribution Wires Business as approved by the Commission shall be deducted from the Aggregate Revenue Requirement in determining the wheeling charges of Distribution Wires Business of the Distribution Licensee:

Provided that the Distribution Licensee shall submit full details of its forecast of Non-Tariff Income to the Commission along with its application for determination of wheeling charges.

96.2 The indicative list of various heads to be considered for Non-Tariff Income shall be as under:

(a) Income from rent of land or buildings or other assets;

(b) Income from sale of scrap;

(c) Income from statutory investments;

(d) Income from interest on Fixed Deposits (including contingency reserve investment);

(e) Interest on advances to suppliers/contractors;

(f) Rental from staff quarters;

(g) Rental from contractors;

(h) Income from hire charges from contactors and others;

(i) Income from Insurance claim receipt

(j) Income from advertisements, sale of tender document, etc.;

(k) Miscellaneous receipts;

(l) Interest on advances to suppliers;

(m) Excess found on physical verification;

(n) Deferred Income from grant, subsidy, etc., as per Annual Accounts;

(o) Prior period income;

(p) Supervisory charges for contractual works;

(q) Any Other Non-Tariff Income.

Provided that the interest/dividend earned from investments made out of Return on Equity corresponding to the Distribution Wires Business of the Distribution Licensee shall not be included in Non-Tariff Income."

8.8 Income from Other business

8.8.1 Section 51 of Electricity Act 2003, enable Distribution Licensee to engage in any other business for optimum utilisation of its assets as below:

"Section 51. (Other businesses of distribution licensees):

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 subsidises in any way such business undertaking nor encumbers its distribution assets in any way to support such business.

Provided also that nothing contained in this section shall apply to a local authority engaged, before the commencement of this Act, in the business of distribution of electricity."

8.8.2 As per Regulation 90 of GERC MYT Regulation, 2016, the Commission has allowed to share 1/3rd of revenue from the other business after deduction of all direct and indirect costs attributed to such business i.e. 1/3rd of net revenue shared to distribution consumers' needs to be reduced from the Aggregate Revenue Requirement. Relevant extract of GERC MYT Regulations, 2016 is as below:

"90. Income from Other Business

Where the Distribution Licensee is engaged in any Other Business, an amount *equal to one-third of the revenues from such Other Business after deduction of all direct and indirect costs attributed to such Other Business shall be deducted from the Aggregate Revenue Requirement in determining the wheeling charges of Distribution Wires Business of the Distribution Licensee:*

Provided that the Distribution Licensee shall follow a reasonable basis for allocation of all joint and common costs between the Distribution Wires Business and the Other Business and shall submit the Allocation Statement to the Commission, duly audited and certified by the statutory auditors, along with his application for determination of wheeling charges:

Provided further that once the Commission notifies the Regulations for submission of Regulatory Accounts, the applications for tariff determination and truing up shall be based on the Regulatory Accounts:

Provided also that where the sum total of the direct and indirect costs of such Other Business exceeds the revenues from such Other Business, no amount shall be allowed to be added to the Aggregate Revenue Requirement of the Distribution Licensee on account of such Other Business."

8.8.3 In the Discussion Paper, the provision w.r.t Income from Other Business as provided in the MYT/Tariff Regulations of various State Electricity Regulatory Commissions was compared. Further, it is observed that the Section 51 of Electricity Act, 2003 allows Distribution Licensee to be involved in Other business so as to optimally utilise the assets of distribution licensee, which help in reducing cost of serve to the consumers. Considering the above discussion and also reviewing the approach followed in other States, the Commission is of the view to deducted net income from other business from the ARR of the Licensees.

8.8.4 However, to avoid sudden changeover in sharing of income from other business and to incentivise distribution utilities to encourage engage in other business activity, the Commission propose to share 2/3rd of the net income from other business during next Control Period and propose the following modification in the existing Regulation as shown below:

"97 Income from Other Business

97.1 Where Distribution Wires Business of Distribution Licensee is engaged in any Other Business under Section 51 of the Act for optimum utilisation of its assets, an amount equal to two-third of the revenues from such Other Business after deduction of all direct and indirect costs attributed to such Other Business shall be deducted from the Aggregate Revenue Requirement in determining the wheeling charges of Distribution Wires Business of the

Distribution Licensee:

Provided that the Distribution Licensee shall follow a reasonable basis for allocation of all joint and common costs between the Distribution Wires Business and the Other Business and shall submit the Allocation Statement to the Commission, duly audited and certified by the statutory auditors, along with his application for determination of wheeling charges:

Provided further that Distribution Licensee shall maintain separate books of accounts for regulated and non-regulated business.

Provided also that where the sum total of the direct and indirect costs of such Other Business exceeds the revenues from such Other Business, no amount shall be allowed to be added to the Aggregate Revenue Requirement of the Distribution Licensee on account of such Other Business."

8.9 Wheeling loss

8.9.1 With regard to the wheeling losses, it is proposed to add a proviso to bring clarity for determination of trajectory for Wheeling Losses as under:

"99 Wheeling Losses

99.1 The Distribution Licensee under wire business shall be allowed to recover, in kind, the approved level of wheeling losses arising from the operation of the distribution system:

Provided that the Commission may stipulate a trajectory for Wheeling Losses in accordance with Regulation 18 of these Regulations as part of the Order on the Multi-Year Tariff Petition filed by the Distribution Licensee."

9 DISTRIBUTION-RETAIL SUPPLY BUSINESS

The section discusses the regulatory provisions regarding the terms and conditions for determination of tariff for Retail Supply Business of Distribution Licensee in the State of Gujarat.

9.1 Components of Tariff

9.1.1 Regulation 94 of the GERC MYT Regulations, 2016 specifies the ARR component for the Wire Business of Distribution license as follows:

"94. Components of Tariff

94.1 The tariff for retail supply by a Distribution Licensee shall provide for recovery of the Aggregate Revenue Requirement of the Distribution Licensee for the financial year, as approved by the Commission and comprising the following:

(a) Cost of own power generation /power purchase expenses;

(b) Transmission charges

(c) SLDC Fees & Charges;

(d) Depreciation;

(e) Interest and Finance Charges;

(f) Interest on working capital and on consumer security deposits;

(g) Operation and Maintenance expenses;

(h) Bad debts written off, if any;

(i) Return on Equity;

(j) Balance Aggregate Revenue Requirement for Distribution Wires Business, as determined under Chapter 7of these Regulations, after deducting income from Wheeling Charges payable by Distribution System Users other than the retail consumers getting electricity supply from the same Distribution Licensee;

minus:

(k) Non-Tariff Income;

(l) Income from Other Business, to the extent specified in these Regulations;

(m) Receipts on account of cross-subsidy surcharge;

(n) Receipts on account of additional surcharge on charges for wheeling:

Provided that Depreciation, Interest and finance charges, Interest on Working

Capital and Return on Equity for the Retail Supply Business shall be allowed in accordance with the provisions specified in Chapter 3 of these Regulations:

Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, subject to prudence check:

Provided also that the receipt of revenue on account of cross-subsidy surcharge shall be considered only at the time of truing up exercise, based on actual receipts as per Audited Accounts."

9.1.2 As discussed in Section 8.28.2, the following regulation is proposed for the next control period:

*"**101 Components of Tariff***

101.1 Tariff for retail supply by a Distribution Licensee shall provide for recovery of the Aggregate Revenue Requirement of the Distribution Licensee for the financial year, as approved by the Commission and comprising the following:

(a) Cost of own power generation /power purchase expenses including Inter-State Transmission Charges net of rebate on power purchase;

(b) Intra-State Transmission charges

(c) SLDC Fees & Charges;

(d) Depreciation;

(e) Interest and Finance Charges on Loan Capital & Return on Equity and/or Return on Capital Employed ;

(f) Interest on working capital and on consumer security deposits;

(g) Operation and Maintenance expenses;

(h) Bad debts written off, if any;

(i) Income Tax;

(j) Balance Aggregate Revenue Requirement for Distribution Wires Business, as determined under Chapter 7 of these Regulations, after deducting income from Wheeling Charges payable by Distribution System Users other than the retail consumers getting electricity supply from the same Distribution Licensee;

minus:

(k) Non-Tariff Income;

(l) Income from Other Business, to the extent specified in these Regulations;

(m) Receipts on account of cross-subsidy surcharge;

(n) Receipts on account of additional surcharge on charges for wheeling;

(o) Revenue from Sale of Surplus Power (Other than to retail consumers):

Provided that depreciation, interest and finance charges on loan capital & return on equity and/or return on capital employed and interest on working capital and income tax for the Retail Supply Business shall be allowed in accordance with the provisions specified in Chapter 3 of these Regulations:

Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts if the income/expenses in that prior period have been allowed on actual basis, on a case to case basis, subject to prudence check:

Provided also that all penalties and compensation payable by the Distribution Licensee to any party for failure to meet any Standards of Performance or for damages/accidents, as a consequence of the orders of the Commission shall not be allowed to be recovered through the Aggregate Revenue Requirement: whereby the details of penalties and compensation paid or payable, if any, is required to be submitted to the Commission along with the Petition under these Regulations:

Provided also that the receipt of revenue on account of cross-subsidy surcharge shall be considered only at the time of truing up exercise, based on actual receipts as per Audited Accounts."

9.1.3 Further, in line with the discussion in Section 8.4, the following modification in existing regulation is proposed:

"101.2 Tariff for the Retail Supply Business of a Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Retail Supply Business:

Provided that where Distribution Licensee is not able to submit audited and certified separate accounts for Distribution Wires Business and Retail Supply Business, the Allocation Matrix as provided under Regulation 94 of these Regulations shall be applicable:

Provided further that the Operation and Maintenance expenses shall be allocated between Distribution Wires Business and Retail Supply Business, by considering the percentages specified in the Allocation Matrix for employee expenses, administration and general expenses, and repair and maintenance expenses, as weights for determining the weighted average allocation percentage for operation and maintenance expenses:

Provided that Distribution Licensee shall be penalised as per Regulation 35.12 of these Regulations, in case it fails to maintain separate books of accounts for Distribution Wire Business and Retail Supply Business from the second / third year of Control Period."

9.1.4 Regulation 94.3 of GERC MYT Regulation, 2016 specifies that the tariff for retail supply by the Distribution Licensee shall be determined by the Commission on the basis of an application for determination of tariff made by the Distribution Licensee. It is to be noted that, there are seven SEZ/SIR in state of Gujarat, having distribution license namely Dahej (SEZ), GIFT (SEZ), Deendayal Port Authority (SEZ), AIVPL (SEZ), MUL (SEZ), Dholera (SIR) and Mandal Becharaji (SIR). Out of the above, distribution license were issued to 2 SEZ in third control period, and are expected to commence their operation in the next control period. However, existing provision of GERC MYT Regulation, 2016 doesn't clarify the applicability of tariff on the retail consumers of new deemed Distribution Licensee (specifically SEZ developer or any other licensee as defined under section 14 of the Electricity Act 2003) till the time of determination of tariff for respective licensee. Thus, for further clarification in philosophy for determination of tariff for retail supply of electricity, following proviso is proposed:

"101.3 Tariff for retail supply by Distribution Licensee shall be determined by the Commission on the basis of an application for determination of tariff made by Distribution Licensee in accordance with Chapter 2 of these Regulations.

Provided further that tariff for retail supply may comprise any combination of fixed/demand charges, energy charges, and any other charges, for the purpose of recovery from the consumers, as may be stipulated by the Commission:

Provided also that in case of a Deemed Distribution Licensee whose tariff is yet to be determined by the Commission till the date of coming into effect of these Regulations, the Commission may determine the ceiling Tariff for retail supply that may be charged by such Distribution Licensee till such time as *considered appropriate by the Commission."*

9.2 Rebate to Retail Consumers

9.2.1 The Commission in their past Order has observed the need of incentivizing consumers for taking supply at higher voltages, bulk consumption, maintain power factor as per code, etc. This could help licensee to reduce distribution losses and improving system reliability. Accordingly, to enable the Licensee to provide such incentive to consumers, slight modification in existing proviso is proposed as under:

"101.4 Distribution Licensee may propose other rebates for inter-alia, taking supply at higher voltages, bulk consumption, power factor, etc., as a part of their Petition, and the revenue impact of rebates shall be passed on through the Aggregate Revenue Requirement and tariffs, subject to the Commission's approval.

101.5 Distribution Licensee shall be allowed to offer a rebate to the consumers on tariff and charges determined by the Commission:

Provided that 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:

Provided further that the impact of such rebates given by Distribution Licensee shall be borne entirely by the Distribution Licensee and impact of such rebate will not be allowed to be passed through to the consumers, in any form:

Provided also that such rebates shall not be offered selectively to any consumer/s, and shall have to be offered to the entire consumer category/ sub-category/ consumption slab in a non-discriminatory manner."

9.3 O&M Expense

9.3.1 Regulation 94.8 of the GERC MYT Regulations, 2016 states that the O&M expenses shall be derived on the basis of the average of the actual O&M expenses for the three (3) years ending March 31, 2015, which shall be considered as O&M expenses for FY 2013-14. Thereafter, this base O&M expenses shall be escalated by 5.72% per annum to arrive at the O&M expenses for the respective years in the Control Period. Relevant Regulation of GERC MYT Regulations, 2016 in this regard is recreated as under:

"94.8 Operation and Maintenance expenses:

a) The Operation and Maintenance expenses shall be derived on the basis of the average of the actual Operation and Maintenance expenses for the *three (3) years ending March 31, 2015, subject to prudence check by the Commission.*

The average of such operation and maintenance expenses shall be considered as operation and maintenance expenses for the financial year ended March 31, 2014 and shall be escalated year on year at the escalation factor of 5.72% to arrive at operation and maintenance expenses for subsequent years up to FY 2020-21.

Provided that in case, the Distribution Licensee has been in operation for less than three (3) years as on the date of effectiveness of these Regulations, the O&M Expenses shall be determined on case to case basis."

Suggestion/Comment on Stakeholders:

Escalation Factor:

1) Adani Power has submitted that moving average of WPI & CPI may be considered equivalent to the number of years for the control period so as the expenses reflect the actual escalation during the corresponding period.

2) MUL has submitted that instead of considering average of last 8 to 10 years' WPI and CPI, average of last 3 years' WPI and CPI applied shall be considered for projections. Further, for the Truing-up of O&M Expense, escalation factor shall be considered on actuals.

3) GUVNL has submitted that as per the last four years details of O&M Expenses, the actual overall escalation for State owned Distribution Companies is around 12% per annum (excluding exceptional increase in employee cost due to pay revision). Thus, the growth factor and escalation factor need to be considered in a manner which captures increase in O&M expenses in realistic manner i.e. at least at 12% per annum.

4) TPL has submitted that 8-10 years moving average of WPI & CPI for deriving Escalation Factor (indxn) is not reflective of current market conditions. Therefore, it is suggested to consider 3-Years Average of WPI & CPI for Escalation Factor for projection of O&M Expense subject to adjustment of actual WPI & CPI.

Projection of O&M Expense:

5) FOKIA has submitted that smart meter would increase the O&M expense of distribution licensee. The additional O&M expense should be met from the gain of improvement in metering efficiency, billing efficiency and revenue efficiency due to providing smart meters. Further it has stated that, if there is any shortfall in expense and gains, the same shall not be passed on to the consumers.

6) MUL has submitted that assets are being built by consumers/developers on its own cost and is being handed over to the Distribution Licensee to maintain the same and hence it should be added while calculating R&M expenses. Further, it has submitted that any type of one-time expenses (such as one time IT infra cost, registration cost, statutory and legal charges, consultancy charges, advertisement cost, Petition Fees etc.) incurred shall be allowed separately under O&M expense.

7) GUVNL has submitted that the distribution business is continuously expanding in nature and hence requirement of R&M expense, Employee expense and A&G expense is continuously increasing along with expansion of network, increase in number of consumers and quantum of supply over and above inflationary increase of existing expenses. As per formula proposed in the discussion paper, increase in R&M expenses is sought to be linked with increase in Gross Fixed Asset by allowing escalation with constant 'K". Similarly, in respect of Employee expenses, the definition of Growth Factor (Gn) is not clear and it also not clear as to how increase in Employee expenses due to expansion in distribution network, increase in sales and consumer base will be captured while approving the Employee Expenses. Whereas for A&G expenses, only inflationary increase is provided without providing any escalation due to increase in distribution network, sales quantum and consumer base. GUVNL also submitted that with increase in number of consumers and quantum of sales, there is requirement to increase administrative set up. Thus, A&G expenses along with R & M expenses and Employee expenses need to be compensated correspondingly.

8) TPL has submitted that A&G Expense also depends on business growth. Thus, there is a need to factor necessary consideration of business growth in the formula of A&G Expenses. It has also stated that the ‘K’ Factor shall be well defined in the regulations, so as to avoid ambiguity in this matter. Further, it has highlighted that Discussion Paper proposes separate approval process for legal/litigation expenses and also seeks

documentary evidence. In this regards it has submitted that, such provisions in the tariff Regulations shall amount to micromanagement of utility's expenditure and it have not come across any such provision in any Tariff Regulations of Other SERCs. It has also stated that Legal expenses are part and parcel of any business and are dependent upon the complexity of business and its impact on the Utility.

Efficiency Factor:

9) MUL has submitted that initially, the efficiency factor, Xn may be considered as Nil. Same may subsequently be determined based on a separate detailed study at the time of mid-term review of the MYT Control Period.

10) GUVNL has submitted that increase in O&M expenses are considered as controllable factor and required to be borne by distribution licensee under the sharing mechanism. Therefore, reducing the O&M expenses with efficiency factor will lead to double implication for distribution licensee for the same parameter, namely implication under sharing mechanism and implication of reduction in O&M expenses due to consideration of efficiency factor in the O&M formula. Therefore, the formula for determination of O&M expenses needs to be corrected.

11) TPL has submitted that O&M Expense should not be reduced by applying Efficiency Factor.

Commissions View:

9.3.2 The Commission has considered the suggestion made by the stakeholders' and based on the discussion in Section 8.3, the following regulation is proposed:

"104 Operation and Maintenance expenses:

104.1 The Operation and Maintenance shall be derived on the basis of the average of the actual audited Operation and Maintenance expenses for the past ten Years ending March 31, 2022, excluding abnormal Operation and Maintenance expenses, if any, subject to prudence check by the Commission:

Provided that average of such Operation and Maintenance expenses shall be considered as Operation and Maintenance expenses for the Year ended March 31, 2018, and shall be escalated at the respective escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22 and FY 2022-23, to arrive at the Operation and Maintenance expenses for the base year ending

March 31, 2023;

Provided further that escalation rate for FY 2018-19, FY 2019-20, FY 2020-21, FY 2021-22 and FY 2022-23, shall be computed by considering (WEWPI) weightage to the average yearly inflation derived based on monthly Wholesale Price Index of the respective financial year as per the Office of Economic Advisor, Ministry of Commerce and Industry, Government of India and (WECPI) weightage to the average yearly inflation derived based on monthly Consumer Price Index for Industrial Workers (all-India) of the respective financial year as per the Labour Bureau, Government of India.

104.2 Operation and Maintenance expenses for nth year of the Control Period shall be determined based on the formula shown below:

O&Mn = (R&Mn + EMPn + A&Gn) x (1 - Xn) + Terminal Liabilities and other one-time expenses

Where,

R&Mn –Repair and Maintenance Costs of Distribution Retail Supply Business for the nth year;

EMPn –Employee Cost of Distribution Retail Supply Business for the nth year;

A&Gn –Administrative and General Costs of Distribution Retail Supply Business for the nth year;

Xn -Efficiency factor for nth Year. Value of Xn to be considered as zero till such time the same is determined through a study by the Commission:

Provided that Terminal Liabilities and other one-time expenses shall be allowed separately on actual basis subject to prudence check.

104.3 It should be ensured that all such expenses capitalized should not form a part of the O&M expenses being specified here. The above components shall be computed in the manner as specified below:

*(i) R&Mn = K * GFA * (1+Index Escn)*

*(ii) EMPn+ A&Gn= (EMPn-1 + A&Gn-1) * (1+Index Escn)*

Where,

‘K’ is a constant (expressed in %) governing the relationship between R&M costs and Gross Fixed Assets (GFA) for the Control Period. The value of ‘K’

will be calculated based on the R&M expenses and GFA for past ten years (or all available years in case of utilities operating for less than 10 years as on April 01, 2022) ending March 31, 2022 approved by the Commission, subject to prudence check and any other factor considered relevant by the Commission;

'GFA' is the Opening balance of the gross fixed assets of the nth year.

EMP n-1 - Employee Cost of Distribution Retail Supply Business for the immediately preceding year;

A&G n-1- A&G of Distribution Retail Supply Business for the immediately preceding year;

Provided that for first year of control period EMP n-1 and A&G n-1 shall mean Employee and A&G expenses of base year as derived in Regulation 104.1 above;

Index Esc means the average Inflation escalation to be considered on the basis weightage of WPI and CPI respectively of the relevant year and to be computed as below:

*Index Escn = WECPI*CPIn + WEWPI*WPIn*

Whereby,

WECPI : Weightage of CPI Index and;

WEWPI: Weightage of WPI Index;

'WPIn' (expressed in %) means the average yearly inflation of Wholesale Price Index (all commodities) over the years for the nth year.

'CPIn' (expressed in %) means the average yearly inflation of Consumer Price Index (Industrial workers) over the years for the nth year.

Note: Source for CPI and WPI calculation as under:

Wholesale Price Index numbers as per Office of Economic Advisor, Ministry of Commerce & Industry, Government of India {Base Year: 2011-12 Series};

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India {Base Year: 2001=100}

Provided further that the escalation rate for FY 2023-24 and for the complete control period i.e. FY 2024-25, FY 2025-26, FY 2026-27, FY 2027-28, and FY 2028-29 shall be computed by considering (WEWPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, *2023 for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year average of the yearly inflation of the last ten years ending March 31, 2023 for Consumer Price Index (CPI).*

Provided further that, in the Truing-up of the O&M expenses norms for any particular year of the Control Period, the escalation rate shall be computed by considering (WEWPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Wholesale Price Index (WPI) and (WECPI) weightage to the 10-year moving average of the yearly inflation of the last ten years including the true-up year for Consumer Price Index (CPI).

Note:

(a) For state government owned Distribution Licensees' Retail Supply Business WECPI:WEWPI is to be considered as 75:25.

(b) For Other Distribution Licensees' Retail Supply Business WECPI:WEWPI is to be considered as 45:55.

(c) O&M expense shall be allowed on normative basis and shall be trued-up only to the account of variation in Wholesale Price Index and Consumer Price Index.

(d) Impact of Wage Revision, if any, may be considered at the time of true-up for any Year, based on documentary evidence and justification to be submitted by the Petitioner. Provisioning of wage revision expenses shall not be considered as actual expenses at the time of true-up, and only expenses as actually incurred shall be considered.

(e) Any variation in actual and normative O&M cost excluding any abnormal expenses or wage revision shall be subject to the sharing of efficiency gains or losses as per framework specified in this Regulations.

(f) In the case of a Deemed Distribution Licensee whose tariff is yet to be determined by the Commission till the coming into force of these Regulations, the Commission may determine the Operation and Maintenance expenses on a case to case basis.

(g) For the purpose of estimation, the same Index Escn value as derived for FY 2024-25 shall be used for all years of the Control Period. However, at the time of true-up of any particular year the Commission will consider the actual values of the WPI and CPI over past ten years including True-up year."

9.4 Bad Debts Write-off

9.4.1 In regard to Bad-Debts write-off, Regulation 94.9 of GERC MYT Regulation, 2016 specifies as follows:

"94.9 Bad debts written off:

94.9.1 The Commission may allow bad debts written off as a pass through in the Aggregate Revenue Requirement, based on the trend of write off of bad debts in the previous years, subject to prudence check:

Provided that the Commission shall true up the bad debts written off in the Aggregate Revenue Requirement, based on the actual write off of bad debts excluding DPC waived off, if any, during the year, subject to prudence check:

Provided further that if subsequent to the write off of a particular bad debt, revenue is realised from such bad debt, the same shall be included as an uncontrollable item under the Non-Tariff Income of the year in which such revenue is realised."

9.4.2 Further, the Commission has discussed that the existing provision doesn't specify any celling on allowable bad debts written off as a pass through in the Aggregate Revenue Requirement. In order to safeguard the interest of honest paying consumers, it is proposed to cap the Bad debts written off during a Financial Year.

Suggestion/Comment on Stakeholders:

12) MUL has submitted that capping the write-off during a Financial Year doesn't seem practically feasible and hence the same may not be incorporated in the MYT Regulations.

13) GUVNL has submitted that pursuant to enactment of Insolvency & Bankruptcy Code (IBC) 2016, the matters of non-payment of debts are being settled by National Company Law Tribunal (NCLT) and premise where dues of distribution licensee is pending is transferred to new party through liquidation proceedings by NCLT. The parties/applicant who have acquired premise/assets on "as is where is" basis through NCLT proceedings are claiming power supply without payment of dues of old parties citing the reason that acquired asset /premise is free from any incumbrances. Further, under the IBC Code, 2016, Distribution Licensees is being considered as operational/unsecured creditors and therefore gets least priority in the share from liquidated assets after Secured/Financial Creditors. Thus, Distribution Licensees have to wait for their turn when

process of distribution of liquidation proceedings commences to recover their share as operational/unsecured creditors after disbursement to the financial creditors first. This leads to non-recovery of electricity dues from consumers/premise went into NCLT proceedings. Accordingly, GUVNL has requested to make specific provision in the Regulations providing that in case of non-recovery of dues by Distribution Licensee on account of NCLT proceedings, such dues shall be allowed as pass through on actual basis.

Commissions View:

9.4.3 Based on above discussions, the Commission is of the view to introduce capping of bad-debts write-off during a financial year. Accordingly, the following is proposed for more clarification in bad-debts write-off:

“105 Bad debts written off:

105.1 The Commission may allow bad debts written off as a pass through in the Aggregate Revenue Requirement, based on the trend of write off of bad debts in the previous years, subject to prudence check:

Provided that the Commission shall true up the bad debts written off in the Aggregate Revenue Requirement, based on the actual write-off of bad debts excluding DPC waived off, if any, up to a ceiling of 0.5% of sales revenue during the year, subject to prudence check:

Provided further that if subsequent to the write off of a particular bad debt, revenue is realised from such bad debt, the same shall be included as an uncontrollable item under the Non-Tariff Income of the year in which such revenue is realised.”

9.5 Capital Investment Plan

9.5.1 Regulation 95 of GERC MYT Regulation, 2016 specifies that Distribution Licensee shall submit a detailed capital investment plan of retail supply business for each year of the Control Period for meeting the requirement of load growth, reduction in distribution losses, increase in collection efficiency, metering, consumer services, etc., to the Commission for approval, as part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period. Further, in line with the discussion in Section 8.5,the following regulation is proposed in the draft regulation:

“106 Capital Investment Plan

106.1 Distribution Licensee shall submit a detailed capital investment plan, *financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, reduction in distribution losses, increase in collection efficiency, metering, consumer services, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.*

106.2 Distribution Licensee shall be required to ensure optimum investments to enhance efficiency, productivity and meet performance standards prescribed by the Commission.

106.3 Distribution Licensee shall submit the Capital Investment Plan as specified in Chapter 2 of these Regulations.

106.4 Capital Investment Plan shall be a least cost plan for undertaking investments and shall cover all capital expenditure projects of a value as specified in Guidelines for in-principle clearance of proposed investment schemes as provided in Annexure III of these Regulations or such other amount as may be stipulated by the Commission from time to time, and shall be in such form as may be stipulated

106.5 The Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required showing the need for the proposed investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the Distribution Wire Business.

106.6 The Commission shall consider the Capital Investment Plan along with the Aggregate Revenue Requirement for the entire Control Period submitted by the Distribution Retail Supply Business taking into consideration the prudence of the proposed expenditure and estimated impact on Distribution Wire Business.

106.7 Capital investment plan shall incorporate list of schemes in order of priority so as to enable the Commission to approve the schemes in that order and in case lesser amount of capital expenditure is to be approved then the schemes of lower priority could be disapproved.

106.8 The Distribution Retail Supply Business shall submit, along with the Petition for determination of Aggregate Revenue Requirement on each year of the control period, details showing the progress of capital expenditure projects, together with such other information, particulars or documents as the Commission may require to assess such progress."

9.6 Sales Forecast

9.6.1 GERC MYT Regulations, 2016 provides for submission of category / sub-category / slab-wise sales forecast based on the past data and reasonable assumptions regarding the future. Further, GERC has also framed guidelines for procurement of power by the Distribution Licensees in 2013, which provides as follows:

> *"3. Every year by 31st January, the Distribution licensees shall submit power procurement plan for 5 years which will include:*
>
> *a. Peak load and energy forecasts of their respective license areas for each of the successive 10 years. The peak load and energy forecasts shall be made for the overall Area of Supply.*
>
> *b. Anticipated power supply position for each of the successive five years along with the projections for additional requirement of procurement of power, if any.*
>
> *c. Hourly load duration projection for each of the successive 5 years."*

9.6.2 Central Electricity Authority (CEA) on April 2023 published draft "Guidelines for Medium and Long Term Power Demand Forecast", with an objective to serve as a guiding document for power utilities to bring uniformity in their power demand forecast approach. The draft guidelines are summarized as follows:

- Forecast to be prepared for medium term (1 to 5 years) and long term (at least for next 10 years), which should be reviewed and updated on yearly basis;
- Apart from forecast at Discom and yearly levels, attempts should be made for granular forecast to facilitate power infrastructure planning.
  - Spatial - zonal/circle/district/sub-station/transformer level
  - Time - month-wise/day-wise/hour-wise/time-block wise
- Forecast should be carried out for at least three scenarios – Optimistic scenario, Business-As-Usual (BAU) scenario & Pessimistic scenario, duly taking into consideration the extreme weather parameters, business cycle, impact of emerging aspects, etc. Advanced statistical tools like Multivariate Regression Analysis should also be used for this purpose.
- The power demand forecast should be done under the unrestricted scenario which essentially is reflective of the case when all the unserved demand currently not served by the utilities due to various supply side barriers such as generation & network constraints (resulting in planned load shedding and unplanned outages) is also included.

- Forecasting method should aim at analysing past consumption data of each category separately and factoring in impacts of emerging aspects to arrive at appropriate future growth trends. CEA has suggested the use of Partial End Use Method (PEUM), which is used for carrying out Electric Power Survey (EPS) exercises.
- The forecasting results obtained should be validated through at least one different method, say Econometric Method.

Suggestion/Comment on Stakeholders:

6. GUVNL has submitted that development and implementation of demand forecasting tools with use of Artificial intelligence / Machine Learning will take considerable time. Considering that limited time period is available with DISCOMs for preparation of MYT projects based on demand and sales forecasts, GUVNL has requested the Commission that the demand in sales forecasting tool using AI/ML will be implemented at the time of filing for mid-term review of ARR.
7. Prayas Energy Group has proposed that the DISCOMs should submit a detailed load research study with consumer category-wise load curves at the beginning of every MYT period. This should be part of the tariff petition of DISCOMs. The load research study should be based on consumer, feeder and DT meter data as well as survey information on appliance usage, where relevant. Energy and Demand requirements for a ten-year period should be based on projections made as per the load curves of each consumer category. Such an approach (as opposed to rule-of-thumb approaches of assuming load factors) will account for seasonal variations and enable scenarios for load shifting. Trends with respect to open access, captive consumption should also be considered taking into account, migration behaviour of consumers, existing contract durations etc. 10-year plans for solarisation of agriculture (especially under KUSUM A and C) should be submitted to account for load shifting as well as power procurement due to solarisation. The model for demand forecasting should include scenarios and should be shared with the Commission along with assumptions and data. Demand forecasts for a 10 year period should be revised during the mid-term review process. Projections for agricultural demand should be based on data from a large and geographically diverse sample size AMR/AMI-enabled segregated agricultural feeders. The norm should be determined based on the methodology specified by the Commission using the feeder input data. The data should be published on the DISCOM websites on a monthly basis.
8. FOKIA has stated that the sales and Demand Forecast has a Direct bearing on Energy Requirement and Power Purchase. Therefore, it is necessary that the actual energy consumption of tariff category wise shall be submitted by the distribution licensee along

with the tariff petition.

Commissions View:

9.6.3 Accordingly, in the wake of guidelines, the following Regulation is proposed in the draft Regulations:

"107 Sales and Demand Forecast

107.1 Distribution Licensee shall make an assessment of demand (MW) during peak and off-peak period and energy requirement (MU) for each month of the ensuing year (Short term) and for next 5 (five) years (Long-term). The peak demand (MW) and energy sales (MU) shall be estimated for each tariff category, sub-category of consumers. The forecast shall be done based on load duration curve explicitly defining the base load and peak load in such a way that adequate unrestricted and uninterrupted (24x7) power supply can be ensured to all categories of consumers.

107.2 Distribution Licensee shall submit a forecast of the expected sales of electricity to each tariff category/sub-category and to each tariff slab within such tariff category/sub-category to the Commission for approval along with the Multi-Year Aggregate Revenue Requirement for the entire Control Period, as specified in these Regulations.

Provided that while estimating monthly demand and energy sales forecast, the Distribution Licensee(s) should carry out for at least three scenarios – Optimistic scenario, Business As Usual (BAU) scenario & Pessimistic scenario, duly taking into consideration various factors but not limited to the following:

(a) Historical as well as current year data

(b) New consumer addition under various categories

(c) Change in Consumption Pattern

(d) Trends with respect to open access, captive consumption, migration behaviour of consumers, existing contract durations etc.

(e) Growth in the consumption of power intensive sectors

(f) Weather forecast and seasonal variations;

(g) Overall economic growth;

(h) Activities and Enable scenarios for load shifting such as solarisation of Agricultural connections and feeders under various schemes, etc.

(i) Projected efficiency gains due to implementation of T&D loss reduction initiatives and other improvement programmers;

(j) Energy Conservation and Energy Efficiency measures planned

(k) Likely impact of implementation of Demand Side Management (DSM)

(l) Increase in penetration consumption from Distributed Energy Resources viz. Rooftop Solar and Electric Mobility

107.3 The sales forecast shall be based on past data and reasonable assumptions regarding the future:

Provided that where the Commission has stipulated a methodology for forecasting sales to any particular tariff category, the Distribution Licensee shall incorporate such methodology in developing the sales forecast for such tariff category:

Provided further that Distribution Licensee shall undertake sales and demand forecast based on methods and tools including load research studies, advance statistical methods including multivariate regression analysis, partial end use method (PEUM), econometric methods, and also explore use of various IT applications, including Artificial Intelligence and Machine Learning (AI/ML) to improve accuracy.

107.4 The Commission shall examine the forecasts for their reasonableness based on growth in the number of consumers, pattern of consumption, losses and demand of electricity in previous years and anticipated growth in the next year and any other factor, which the Commission may consider relevant and approve. the sales forecast with such modifications as deemed fit. The Distribution Licensee(s) shall develop a robust database of all consumers with desired particulars regarding their demand to facilitate the forecasting process in accordance with the direction given by the Commission.

Provided that in the second year of the Control Period, Distribution Licensee shall also submit a detailed load research study, based on consumer, feeder and DT meter data as well as survey information on appliance usage etc., with consumer category wise load curves, for the remaining years of the Control Period."

9.7 Power Procurement

9.7.1 Power purchase cost accounts for approximately 70%-80% of the total cost of the retail supply business. Therefore, the monitoring of power procurement is amongst the most vital aspect of distribution retail supply plan to ensure transparent, economic and optimal procurement of power by the Distribution Licensee. Further, various provisions of the Electricity Act, 2003 provides for regulating purchase of electricity by the distribution licensee. It is to be noted that Section 86(1)(b) of the Electricity Act, 2003 confers powers on the Commission to regulate the electricity purchase and procurement process of Distribution Licensees including the price at which electricity shall be procured from the Generating Companies or Licensees or from other sources through agreements for purchase of power, for distribution and supply within the State.

9.7.2 It is to be noted that, the Commission has already issued the Guidelines for Procurement of Power by Distribution Licensees in order to ensure standardization and reduce the subjectivity in process of procurement of power through a transparent and economic mechanism as well as to protect consumers' interest. The Guidelines of Procurement of Power clearly specifies that every year by 31st January, the Distribution Licensee is required to submit Power Procurement Plan for 5 years.

9.7.3 However, the GERC MYT Regulation, 2016 doesn't specifies the any regulation for monitoring of power procurement by distribution company. Further, it also fails to address various situations under which the Distribution Licensee is allowed to enter into additional agreement or arrangement for procurement of power and treatment of power purchase from unapproved sources.

9.7.4 Further, in the Discussion paper, it has been highlighted that the Electricity (Amendment) Rules, 2022 notified by the Ministry of Power, Government of India, provided that the Central Government, in consultation with Central Electricity Authority will issue Resource Adequacy Guidelines for assessment of resource adequacy during the generation planning stage (one year or beyond) as well as during the operational planning stage (up to one year). Resource Adequacy has attained a center stage in the power procurement planning. It also provided that the SERC shall frame regulations on resource adequacy, based on which the distribution licensees shall formulate the resource adequacy plan and seek approval of the SERC. Central Electricity Authority's, Guidelines for Power Procurement Planning is summarised as below:

- Distribution Licensees shall prepare its Long-term Discom Resource Adequacy Plan (LT-DRAP) for a 10 year horizon [Long-term Distribution Licensee Resource Adequacy Plan (LT-DRAP)], on an annual rolling basis, to meet their own peak and electrical energy requirement, which shall be vetted by CEA.
- The Distribution Licensees shall take inputs if required from the Long-term Discom

Resource Adequacy Plan (LT-DRAP), Planning Reserve Margin (PRM), capacity credits, etc., while formulating their LT-DRAP and submit their plans to CEA by the month of September for the period starting from the month of April in the subsequent year.

- CEA shall vet the LT-DRAP along with details for meeting the RAR of national peak for the utility may be submitted to SERC/JERC by the month of November for the period starting from the month of April in the subsequent year for their approval.
- The Resource Adequacies studies by the Distribution Licensees would require inputs regarding long-term demand projections, demand pattern, load growth estimates, RE generation profile, technical specification of base load generating stations (ramp rates, minimum technical load, heat rate, start-up cost, time, etc.), generation capacities (existing and planned), various costs parameters (capital cost, variable cost, O&M costs, start-up and shut-down costs, reserve offers) of the generators, historical forced outage rates and planned maintenance rates of generation capacities, tie line details and transmission expansion plans, RPO / HPO / Energy Storage obligation targets, spinning reserve and planning reserve margins, etc.

Suggestion/Comment on Stakeholders:

1) GUVNL has submitted that the Electricity Rules,2022 notified by Ministry of Power, Govt of India, provides that SERC shall frame regulations on resource adequacy, based on which the distribution licensees shall formulate the resource adequacy plan and seek approval of the SERC. Considering above, the DISCOMS shall formulate resource adequacy plan and seek approval from the Commission once the regulations on resource adequacy is framed by the Commission.

2) Prayas Energy Group has submitted that plans should be scenario based to account for cost impacts and resource adequacy based on various technologies, sales growth and load shifting, etc. Demand side measures with respect to increase in appliance efficiency, impact of time of day tariffs should also be considered in resource adequacy plans. The role of storage, especially BESS as well as short-term power procurement should also be part of RA plans. There should also be consideration of renewable capacity addition and capacity value of RE procurement. Scenarios for RE generation need to be in sync with demand variations to the extent that they are both weather dependent. Thus, it is important to

understand the extent to which weather simultaneously impacts both demand and VRE generation, and these should be incorporated to the extent possible. The use of production cost and capacity expansion models for RA is of paramount importance. The model used by the DISCOMs along with data and assumptions should be shared with the Commission. The models should have 15-minute time resolution. Resource Adequacy plan of the DISCOMs should be shared publicly and finalized based on a public consultation process. The Resource Adequacy plan approved by the Commission should be followed and all investment and power procurement decisions should be based on what has been approved as part of the Resource Adequacy plan. The Resource Adequacy plan approved should also state the investment requirements to meet the Resource Adequacy plan.

3) TPL has submitted that Resource Adequacy is binding distribution company to meet their requirement with long term tie-up of 75-85%, whereas on the other hand, distribution company are asked to provide Open Access even to Consumer of 100 kW and above without recovering commensurate CSS/ Additional Surcharge. Further, MoP Rules also envisage purchase of green power from the Discom wherein it is provided to cap the Green tariff. Accordingly, TPL has suggested to consider power purchase plan over the MYT period on case-to-case basis as per the Commission's prevailing Power Procurement Guidelines.

4) FOKIA has submitted that there are 11 numbers of 210 MW Thermal power Station at Ukai, Gandhinagar and Vanakbori which have completed 35 to 44 years of service and are working at less than 25% PLF and attracting full fixed costs. While the variable cost of these power plants is about Rs. 4.25/unit, and are not operated as per the merit order dispatched. As these plants are not declared "out of Service", no new power plants can be taken up with the more efficient supercritical boilers.

Commissions View:

9.7.5 Considering the amended Electricity Amendment Rules, 2022, and the Guidelines for Resource Adequacy Planning Framework issued by the Ministry of Power, following regulation is proposed to optimise their power purchase cost and to enter into additional agreement or arrangement for procurement of power from other sources:

"108 Power Procurement

108.1 Power procurement guidelines

108.1.1 Distribution Licensee shall undertake its 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.

108.1.2 All future procurement of short-term or medium-term or long-term power, including Renewable Energy, shall invariably be undertaken through competitive bidding in accordance with Guidelines notified by the Government of India under Section 63 of the Act:

Provided that in case either no competitive bids are received or the bids received are higher than the prevailing market rates or on any other sufficient reason, then the Distribution Licensee may procure medium-term or long-term power under Section 62 of the Act, subject to fulfilling the conditions specified in Regulation 108.1.3 to 108.1.9 of these Regulations.

Provided that in case of any proposal for procurement of power through MoU route, the Distribution Licensee shall obtain prior approval of the Commission.

108.1.3 Every long-term/medium-term agreement or arrangement for power procurement, including on a Standby basis, by a Distribution Licensee from a Generating Company or Trading Licensee or from another source of supply, and any change to an existing agreement or arrangement shall come into effect only with the prior approval of the Commission:

Provided that prior approval of the Commission shall not be required for purchase of power from Renewable Energy sources at the generic/preferential tariff determined by the Commission for meeting its Renewable Purchase Obligation (RPO).

108.1.4 The Petition for approval of power purchase agreement or arrangement shall include the power procurement plan for its duration:

Provided that public consultation shall not be required for adoption of tariff discovered through competitive bidding under Section 63 of the Act:

Provided further that in case of power procurement under Section 62 of the Act, public consultation as stipulated in Regulation 108.1.6 and Regulation 108.1.7 of these Regulations shall be followed.

108.1.5 The Petitioner shall submit a duly completed draft Public Notice for the Commission's approval as per the stipulated template, for *publication as and when intimated by the Commission.*

108.1.6 Upon receipt of a complete petition accompanied by the requisite information, particulars and documents in compliance with the requirements specified in this Regulation, the petition shall be admitted and the Commission or its Secretary or designated Officer shall intimate to the Petitioner that the Petition is ready for publication.

108.1.7 The Petitioner shall, within three days of an intimation given to it in accordance with Regulation 108.1.4 of these Regulations, publish a Public Notice, in at least two English and two Gujarati language daily newspapers widely circulated in the area to which the Petition pertains, outlining the salient features of the proposed agreement or arrangement for power procurement and the impact on the power procurement cost and Tariff, and such other matters as may be stipulated by the Commission, and inviting suggestions and objections from the public:

Provided that the Petitioner shall make available a hard copy of the complete Petition to any person at such locations and at such rates as may be stipulated by the Commission;

Provided further that the Petitioner shall also provide the Petition filed before the Commission along with all regulatory filings, information, particulars and documents in the manner stipulated by the Commission on its internet website:

Provided also that the web-link to the information mentioned in the second proviso to this Regulation shall be easily accessible, archived for downloading and shall be prominently displayed on the Petitioner's internet website:

Provided also that the Petitioner may be exempted by the Commission from providing any such information, particulars or documents as are confidential in nature.

108.1.8 The Commission shall consider a Petition for approval of power procurement agreement or arrangement having regard to the approved power procurement plan of the Distribution Licensee and the following factors:

(a) requirement of power procurement under the approved power procurement plan;

(b) adherence to a transparent process of bidding in accordance with

guidelines issued by the Central Government under Section 63 of the Act, or adherence to the terms and conditions for determination of tariff specified under Chapter 4 of these Regulations;

(c) competitiveness of the proposed tariff vis-a-vis the tariff prevalent in the market and/or tariff discovered through competitive bidding under Section 63 of the Act;

(d) availability (or expected availability) of capacity in the Intra-State Transmission System for evacuation and supply of power procured under the agreement or arrangement; and

(e) need to promote co-generation and generation of electricity from renewable sources of energy.

108.1.9 Upon completion of its consideration of the power procurement agreement or arrangement, the Commission shall:

(a) issue an Order approving the power procurement agreement or arrangement, subject to such modifications and conditions as it may stipulate; or

(b) reject the Petition for reasons to be recorded in writing, after giving the Petitioner an opportunity to be heard.

108.2 Approval of additional power procurement

108.2.1 Distribution Licensee may initiate the process of additional power procurement during the year, in accordance with the Guidelines for Procurement of Power by Distribution Licensees issued by the Commission, as amended from time to time and with prior approval of the Commission.

Provided that the prior approval of the Commission shall not be required for purchase of power from Renewable Energy sources at the generic/preferential tariff determined by the Commission for meeting its Renewable Purchase Obligation (RPO).

108.2.2 Where Distribution Licensee is to procure power on a short-term basis or there is a shortfall due to any reason whatsoever, or failure in the supply of electricity from any approved source of supply during the year, for any reason whatsoever, the licensee may enter into a short-term arrangement or agreement for procurement of power through power exchanges or through a transparent process of open tendering and competitive bidding.

Provided Distribution Licensee shall submit its details, including the quantum, Tariff computations, duration, supplier particulars, method of supplier selection and any such other details to the Commission within fifteen days from the date of entering into an agreement or arrangement, as the Commission may require so as to carry out the prudence check.

Provided that in case procurement of short-term power exceeds the approved annual short term procurement plan, the Distribution Licensee shall obtain prior approval from the Commission or any appropriate body as may have been constituted for the purpose by the Commission.

108.3 Any variation, in the quantum or cost of power procured, including from a source other than a previously approved source, that is expected to be in excess of five per cent, of that approved by the Commission, on a quarterly basis, shall require its prior approval.

Provided that the five per cent limit shall not apply to variation in the cost of power procured on account of changes in the price of fuel for own generation or the fixed or variable cost of power purchase that is allowed to be recovered in accordance with Regulation 115 of these Regulations.

108.4 Where Distribution Licensee has identified a new short-term source of supply from which power can be procured at a tariff that reduces its approved total power procurement cost or when faced with emergency conditions that threaten the stability of the Distribution System, or when directed to do so by the SLDC to prevent grid failure, it may enter into a short-term power procurement agreement or arrangement with such supplier without the prior approval of the Commission.

Provided that Distribution Licensee shall submit to the Commission its details, including the quantum, tariff computations, duration, supplier particulars, method of supplier selection and any such other details as the Commission may require so as to carry out the prudence check within fifteen days from the date of entering into an agreement or arrangement.

108.5 The Commission may permit any Distribution Licensee to make purchase of power without prior approval subject to competitive and transparent process in the event of an unforeseen and an exceptional situation. However, the Distribution Licensee shall not, thereby, be exempted from demonstrating the need and the reason for departure from a competitive process together with the economic justification for the purchase, the means, whereby, in the absence of competition, the

Distribution Licensee proposes to secure the best possible terms and such other information as the Commission may require.

Provided that the Commission shall indicate the ceiling of short-term power purchase price and volume for the ensuing quarter based on the availability of power, past requirement, approved quantum of short-term power in Aggregate Revenue Requirement, approval granted for past quarter and past market performance. The Commission may ask for additional information and data as it may deem necessary for reviewing the forecast for the ensuing quarter and the distribution licensee shall furnish such information within 2 weeks from being asked to do so;

Provided that, where the Commission has reasonable grounds to believe that the agreement or arrangement entered into by the Distribution Licensee does not meet the criteria specified in this Regulation, it may disallow any increase in the total cost of power procurement over the approved level arising therefrom or any loss incurred by the Distribution Licensee as a result, from being passed through to consumers.

108.6 Power Procurement Plan

108.6.1 Distribution Licensee shall prepare a 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:

Provided that such power procurement plan shall be submitted for the Control Period commencing on April 01, 2024, along with the Petition for determination of Tariff for the Control Period from April 01, 2024 to March 31, 2029, in accordance with Chapter 2 of these Regulations;

108.6.2 The power procurement plan of the Distribution Licensee shall comprise the following:

(a) a quantitative forecast of the unrestricted base load and peak load for electricity within its area of supply;

(b) an estimate of the quantities of electricity supply from the identified sources of power purchase, including own generation if any;

(c) an estimate of availability of power to meet the base load and peak load requirement:

Provided that such estimate of demand and supply shall be on month-wise basis in Mega-Watt (MW) as well as expressed in Million Units (MU) in *accordance with the Regulation 107 of these Regulations;*

(d) standards to be maintained with regard to quality and reliability of supply, in accordance with the relevant Regulations of the Commission;

(e) measures proposed for energy conservation, energy efficiency, and Demand Side Management;

(f) requirement for new sources of power procurement, including augmentation of own generation capacity, if any, and identified new sources of supply, based on (a) to (e) above;

(g) sources of power, quantities and cost estimates for such procurement:.

Provided that the forecast or estimates contained in the long-term procurement plan shall be separately stated for peak and off-peak periods, in terms of quantities of power to be procured (in MU) and maximum demand (in MW) as per Regulation 108.8 of these Regulations:

Provided further that the forecast or estimates for the Control Period from FY 2024-25 to FY 2028-29 shall be prepared for each month over the Control Period:

Provided also that the short-term procurement plan shall be prepared as per Regulation 108.9 of these Regulations.

108.6.3 The Commission shall approve the power procurement plan for the Control Period as part of its Order on the MYT Petition.

108.7 Assessment of Availability of Power

108.7.1 Distribution License shall assess the availability of power from different sources for meeting power demand (MW) and energy required (MU) during peak and off-peak periods for each month of the ensuing year (short term) and for next five (5) years (long term).

108.7.2 Distribution Licensees shall have long-term / medium-term tie up to meet load requirement of at least 75% duration of the fifth year. In case of any shortfall to meet load requirement of 75% of duration of the fifth year through long-term / medium-term arrangement, the Distribution Licensee shall initiate the process of long-term procurement of power.

108.7.3 Distribution Licensees shall have long-term / medium-term tie up to meet load requirement of at least 85% of duration of the third year. In case of any shortfall to meet load requirement of 85% of duration of the third *year through long-term / medium-term arrangement, the Distribution Licensee shall initiate the process of medium-term procurement of power.*

108.7.4 The assessment of availability shall be based on the relevant information and inputs but not limited to the following:

(a) share of power from existing generating stations owned or operated by the Distribution Licensee or the State and the Central Sector Generating Plants and other sources of power;

(b) availability of power from renewable energy sources within and outside the State

(c) expected share of the Distribution Licensee from new generating stations due for commissioning for which PPA has been signed or in the process of signing;

(d) power banking arrangements;

(e) trends in captive power consumption;

(f) uprating of existing power plants;

(g) phase out of old stations or non-availability of power due to extended period of maintenance/ renovation & modernization of old generating plants;

(h) planned maintenance schedules of generating stations;

(i) Renewable Purchase Obligation (RPO)

108.7.5 For assessment / calculation of Peak Demand (MW) and Energy Requirement (MU), the following methodology shall be adopted.

(a) generation from existing hydro generating stations shall be based on average of actual generation during last 3 years with suitable adjustments;

Provided that, in case of new hydro generating stations, availability shall be considered as per applicable norms;

(b) generation from existing State thermal generating stations shall be based on the average of actual generation during last three (3) years with suitable adjustments, whereas generation of existing Central Sector thermal generating stations shall be based on the actual generation in previous year;

Provided that, in case of new thermal generating stations, plant availability factor and auxiliary consumption shall be considered as per applicable norms;

(c) generation from existing renewable energy plants within the State shall be taken as actual generation in the previous year, whereas for new plants, capacity utilisation factor (CUF) and auxiliary consumption shall be considered as per applicable norms;

(d) for existing and new Nuclear Power Plants, the plant availability factor and auxiliary consumption shall be considered as per applicable norms;

(e) transmission losses for both ISTS and Intra-State Transmission System shall be considered same as that of previous year.

Provided that, in case of any deviation from above methodology for assessment of availability of power, proper justification shall be provided.

108.8 Long Term Power Procurement Plan

108.8.1 The long-term Power Procurement Plan in terms of peak demand (in MW) and energy requirement (in MU) shall be prepared by Distribution License for 5 (five) years based on the inputs provided by the Distribution Licensee(s) and taking into consideration of the latest Electric Power Survey (EPS) report of Central Electricity Authority. The plan shall be prepared on monthly basis as per the principles laid down in these Regulations.

108.8.2 Distribution License shall submit Month wise details (with year-wise totals) (both in terms of demand in MW and energy in MU) indicating power expected to be produced from state generating stations, central sector generating stations and other sources of power with whom long-term Power Purchase Agreements (PPAs) have been entered into, short-term purchases of electricity and power purchase expenses in terms of capacity charge and energy Charge etc.

(a) Distribution Licensee shall also submit break-up of power purchase cost and quantum of power from each of the generating station, for which expense has been incurred in the past three (3) years;

(b) breakup of energy requirement (in MU) for consumers in its license area and for trading shall be submitted separately along with the long-term power procurement plan.

(c) long-term power procurement plan shall be submitted by Distribution License to the Commission as a part of MYT Petition, in accordance with Chapter 2 of these Regulations;.

108.9 Short-Term Power Procurement Plan

108.9.1 Short-Term Power Procurement Plan shall be prepared by Distribution License for peak and off-peak periods in terms of Demand (MW) and Energy Requirement (MU) taking into account the following:-

(a) weather forecast and seasonal variations;

(b) power transactions through banking;

(c) renewable purchase obligation;

108.9.2 The power procurement plan shall be strictly as per Merit Order principle and it shall be the least cost plan with the ultimate objective of providing safe, secure, reliable and quality power supply to all consumers at economically viable tariffs complying to all relevant standards & Regulations;

Provided that the must run Plants/generators shall be exempted from Merit Order principle.

108.9.3 The short-term power procurement plan shall be submitted to the Commission by 30th November of every year as part of annual Tariff Petition, in accordance with Chapter 2 of these Regulations.

108.9.4 The power purchase quantum and cost shall be calculated based on the estimates for demand and energy requirement."

9.8 Non-Tariff Income

9.8.1 Regulation 97 of GERC MYT Regulation, 2016, specifies the Non-Tariff income relating to the Retail Supply of electricity distribution business as shown below:

"97. Non-Tariff Income

97.1 The amount of Non-Tariff Income relating to the Retail Supply of electricity as approved by the Commission shall be deducted from the Aggregate Revenue Requirement in calculating the tariff for retail supply of electricity by the Distribution Licensee:

Provided that the Distribution Licensee shall submit full details of his forecast of Non-Tariff Income to the Commission along with his application for determination of tariff.

97.2 The indicative list of various heads to be considered for Non-Tariff Income shall be as under:

a) Income from rent of land or buildings;

b) Income from sale of scrap;

c) Income from statutory investments;

d) Income from interest on contingency reserve investment;

e) Interest on advances to suppliers/contractors;

f) Rental from staff quarters;

g) Rental from contractors;

h) Income from hire charges from contactors and others;

i) Income from advertisements, etc.;

j) Meter/metering equipment/service line rentals;

k) Service charges;

l) Customer charges;

m) Recovery for theft and pilferage of energy;

n) Prompt Payment Rebate

o) Miscellaneous receipts;

p) Deferred Income from grant, subsidy, etc., as per Annual Accounts;

q) Prior period income, etc.:

Provided that the interest/dividend earned from investments made out of Return on Equity corresponding to the Retail Supply Business of the Distribution Licensee shall not be included in Non-Tariff Income:

Provided further that any income earned by a Distribution Licensee by sale of power to other Distribution Licensees or to consumers as per Section 49 of the Act using the existing power purchase agreements or bulk supply capacity allocated to the Distribution Licensee's area of supply shall be reduced from the Aggregate Revenue Requirement of the Distribution Licensee for the purpose of determination of tariff."

9.8.2 It is proposed to continue with the prevailing Regulation with slight modification as highlighted below:

"109 Non-Tariff Income

109.1 The amount of Non-Tariff Income relating to the Retail Supply of electricity as approved by the Commission shall be deducted from the Aggregate Revenue Requirement in calculating the tariff for retail supply of *electricity by the Distribution Licensee:*

Provided that the Distribution Licensee shall submit full details of his forecast of Non-Tariff Income to the Commission along with his application for determination of tariff.

109.2 The indicative list of various heads to be considered for Non-Tariff Income shall be as under:

(a) Income from rent of land or buildings or other asset;

(b) Income from sale of scrap;

(c) Income from statutory investments;

(d) Income from interest on Fixed Deposits (including contingency reserve investment)

(e) Interest on advances to suppliers/contractors;

(f) Rental from staff quarters;

(g) Rental from contractors;

(h) Income from hire charges from contactors and others;

(i) Income from Insurance claim receipt;

(j) Income from advertisements, sale of tender, etc.;

(k) Meter/metering equipment/service line rentals;

(l) Service charges, supervision charges for contractual works, etc;

(m) Customer charges;

(n) Recovery for theft and pilferage of energy;

(o) Miscellaneous receipts;

(p) Deferred Income from grant, subsidy, etc., as per Annual Accounts;

(q) Prior period income,

(r) Any Other Non-Tariff Income:

Provided that the interest/dividend earned from investments made out of Return on Equity corresponding to the Retail Supply Business of the Distribution Licensee shall not be included in Non-Tariff Income:

Provided further that any income earned by a Distribution Licensee by sale of power to other Distribution Licensees or to consumers as per Section 49 of the

Act using the existing power purchase agreements or bulk supply capacity allocated to the Distribution Licensee's area of supply shall be reduced from the Aggregate Revenue Requirement of the Distribution Licensee for the purpose of determination of tariff."

9.9 Income from other Business

9.9.1 In line with discussion in Section 8.7, following modification is proposed in existing Regulations:

"110 Income from Other Business

110.1 Where the Retail Supply Business of the Distribution Licensee is engaged in any Other Business under Section 51 of the Act for optimum utilisation of its assets, an amount equal to two-third of the revenues from such Other Business after deduction of all direct and indirect costs attributed to such Other Business shall be deducted from the Aggregate Revenue Requirement in calculating the tariff from retail supply of electricity by the Distribution Licensee:

Provided that the Distribution Licensee shall follow a reasonable basis for allocation of all joint and common costs between the Distribution Business and the Other Business and shall submit the Allocation Statement, duly audited and certified by the statutory auditors, to the Commission along with his application for determination of tariff;

Provided further that Distribution Licensee shall maintain separate books of accounts for regulated and non-regulated business.

Provided also that where the sum total of the direct and indirect costs of such Other Business exceeds the revenues from such Other Business, no amount shall be allowed to be added to the Aggregate Revenue Requirement of the Distribution Licensee on account of such Other Business."

9.10 Distribution Losses and AT&C Losses

9.10.1 Regulation 20 of GERC MYT Regulation, 2016 states that while approving the MYT Petition, the Commission shall stipulate a distribution loss trajectory and same shall be reviewed by the Commission during the Control Period. Relevant extract of regulation is reiterated as below:

"20. Specific trajectory for certain variables

*While approving the MYT Petition**, the Commission shall stipulate a trajectory for the variables, which shall include, but not be limited to Operation & Maintenance expenses, target plant load factor and***

distribution losses for FY 2017-18 *onwards:*

Provided that the utilities shall adhere to the norms as specified in these Regulations for FY 2016-17:

Provided further that the Generating Company, Transmission Licensee, SLDC, ***Distribution Wires Business and Retail Supply Business may seek a review of the trajectory at the time of mid-term review of Aggregate Revenue Requirement for the balance Control Period****."*

9.10.2 Further, in regard to Distribution Losses, Regulation 101 of GERC MYT Regulation, 2016 states as follows:

"101 Distribution Losses

The Distribution Licensee shall recover the approved level of distribution losses arising from the Retail Supply of electricity:

Provided that the distribution loss level for FY 2016-17 may be stipulated in the Tariff Order for FY 2016-17:

Provided further that the Commission may stipulate a trajectory for distribution losses for the period from FY 2017-18 to FY 2020-21 in accordance with these Regulations, as part of the Order on the MYT Petition to be filed by the Distribution Licensee under Regulation 17.2 (a):

Provided also that any variation between the actual level of distribution losses and the approved level shall be dealt with, as part of the Truing up exercise."

9.10.3 Further, in Discussion paper, it was observed that some SERC such as DERC (Delhi Electricity Regulatory Commission) and OERC (Orissa Electricity Regulatory Commission) have adopted the AT&C loss approach for approving the ARR and tariff of distribution licensees. However, considering the fact that such approach shall not be prudent and result in burden to consumers who are paying bill on time for the licensees' inability to collect the billed amounts from certain consumers. Further, the inclusion of collection inefficiency by determining the tariffs on the basis of AT&C loss will result in further increase in the consumer's tariff, if collection efficiency is less than 100%.

9.10.4 Accordingly, it was proposed to continue with Distribution Loss approach for approving the ARR and tariff of Distribution Licensees in the State, with the trajectory of distribution loss being stipulated in the Multi-Year Tariff Order rather than being specified in the Regulations.

Suggestion/Comment from Stakeholders:

1) FOKIA has submitted that to continue with existing approach of considering distribution loss for approving of ARR and Tariff of distribution tariff. It also stated to prescribe Distribution loss calculation methodology in MYT Regulation on similar lines that of revised AT & C losses calculation methodology notified by Central Electricity Authority, Government of India, vide their letter no CEA-GO-13-25/1/2023 DPR Division/73, dated 30-06-2023. FOKAI further submitted that that the sales of unmetered agriculture consumers are more than 194% to 396% of the metered consumers i.e., average 269% of metered agriculture connections as worked out above. Even though the metered and unmetered agriculture consumers are catered power supply from the same feeder for same number of hours of power supply and having similar groundwater availability, rainfall, type of soils, cropping pattern etc. there is disparity in actual consumption of metered agricultural consumers and that of un-metered agriculture consumer only due to the norm of 1700 kWh per Hp per annum. The Commission had adapted normative consumption of 1700 kwh/HP/Annum for unmetered consumers based on Dr. Mishra committee's report in the year 2000. Since than in wake of Jyoti Gram Yojana Agriculture Dominant Feeders (AGDOM) has been commissioned to exclusively cater agricultural consumes (metered and unmetered) for 8 hours in three phases. Thus, the uniform normative consumption of 1700 kwh/HP/Annum for all consumers of all DISCOMs shall be discontinued and normative consumption shall not be considered more than average units/HP/Annum sent out for respective DISCOM.

2) GUVNL has submitted that the implication of non- recovery from consumers. if any is taken care under the pass-through mechanism of gain / losses from working capital requirement and bad debt (normative vs actual requirement) Thus it is appropriate to continue with distribution loss trajectory instead of AT&C loss trajectory for DSICOMS.

3) TPL has submitted that Existing approach of defining T&D Loss results in penalizing better performing utilities and to maintain the lower levels of Distribution losses, Utilities are required to make concerted efforts. Accordingly, it has suggest to revise mechanism wherein uniform target may be provided for all the Utilities in the state.

Commissions View:

9.10.5 In view of above< it is proposed to continue with Distribution Loss approach for approving the ARR and tariff of Distribution Licensees in the State, with the trajectory of distribution loss being stipulated in the Multi-Year tariff order rather than being specified in the Regulations.

9.10.6 Further, the Central Electricity Authority vide its notification dated 30.06.2023 has issued guidelines for standardising the methodology for calculation of AT&C losses as follows:

Table 37: Methodology for calculation of AT&C

A	*Input Energy (MU)*	*Energy Generated - Auxiliary Consumption + Energy Purchased (Gross) – Energy Traded/ Inter State Sales.*
B	*Transmission Losses(MU)*	
C	*Net Input Energy (MU)*	*A-B* ***Open Access/Wheeling unit shall not be included**
D	*Energy Sold (MU)*	*Energy Sold to all categories of consumers excluding units of Energy Traded/Inter-State Sales.* ***Open Access/Wheeling unit shall not be included**
E	*Revenue from Sale of Energy (Rs. Cr.)*	*Revenue from Sale of Energy to all categories of consumers (including Subsidy Booked) but excluding Revenue from Energy Traded /Inter-State Sales.* ***No adjustment shall be made in revenue from sale of energy on account of un-billed revenue**
F	*Adjusted Revenue from Sale of Energy on Subsidy Received basis (Rs. Cr.)*	*Revenue from Sale of Energy (same as E above) minus Subsidy Booked plus Subsidy Received against subsidy booked during the year* ***(including Arrears received during the year, if any)***
G	*Opening Debtors for Sale of Energy (Rs. Cr.)*	*Opening debtors for sale of Energy as shown in Receivable Schedule (Without deducting provisions for doubtful debtors). Unbilled Revenue shall not be considered as Debtors.*
H	*Closing Debtors for Sale of Energy (Rs. Cr.)*	i) *Closing debtors for Sale of Energy as shown in Receivable Schedule (Without deducting provisions for doubtful debts). Unbilled Revenue shall not be considered as Debtors.* ii) *Any amount written off during the year directly from(i)*
I	*Adjusted Closing Debtors for sale of Energy (Rs. Cr.)*	*H(i+ii)*
J	*Collection Efficiency (%)*	*(F+G-I)/E*100*

K	*Units Realized (MU) = [Energy Sold*Collection efficiency]*	*D*J/100*
L	*Units Unrealized (MU)= [Net Input Energy-Units Realized]*	*C-K*
M	*AT&C Losses (%) = [{ Units Unrealized/Net Input Energy}*100]*	*L/C *100*

9.10.7 The Ministry of Power vide its notification dated 30.05.2023 has issues AT&C loss reduction trajectory for state/UT DISCOMs/ Power Department. Further, these trajectories would be applicable for all ongoing scheme or scheme issued by the Government of India from time to time. Also, these trajectories shall be considered by the respective Electricity Regulatory Commission for the determination of Tariff. AT&C loss reduction trajectories for the state DISCOMs from FY 2022 to FY 2028 as approved in above notification is shown below:

Table 38: AT&C Loss Reduction Trajectory

(Distribution loss in %)

DISCOMs	**FY 22**	**FY 23**	**FY 24**	**FY 25**	**FY 26**	**FY 27**	**FY 28**
DGVCL	8.00	7.90	7.80	7.70	7.50	7.50	7.50
MGVCL	10.81	10.31	9.81	9.31	9.00	8.50	8.00
PGVCL	18.22	17.22	16.22	15.00	14.00	13.00	12.00
UGVCL	7.35	7.30	7.25	7.20	7.00	7.00	7.00

9.10.8 Based on the above discussion, the Commission is of the view that the trajectory of distribution losses shall be specified by the Commission as part of the Order on the Multi-Year Tariff Petition filed by the Distribution Licensee. Accordingly, amendment to existing clause is proposed as under:

“113 Distribution Losses

113.1 The Distribution Licensee shall recover the approved level of distribution losses arising from the Retail Supply of electricity:

Provided that the Commission may stipulate a trajectory for distribution losses for the period from FY 2024-25 to FY 2028-29 in accordance with these Regulations, as part of the Order on the MYT Petition to be filed by the Distribution Licensee under Regulation 18 of these Regulations;

Provided further that while stipulating a trajectory for distribution losses as above, the Commission may take into consideration various factors including trajectory approved by Government of India or State Government under any Scheme;

Provided further that any variation between the actual level of distribution *losses and the approved level shall be dealt with, as part of the Truing up exercise;*

9.10.9 Further, at the time of Ture-up of ARR, the DISCOMs shall compute the distribution loss and AT&C loss in line with the methodology specified by the Central Electricity Authority in above said notification.

9.11 Working Capital Norms (Retail Supply)

9.11.1 Regulation 40.5 of GERC MYT Regulation, 2016 specifies the working capital norms for distribution wire business as follows:

"40.5 Retail Supply of Electricity

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

(i) Operation and maintenance expenses for one month; plus

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

(iii) Receivables equivalent to one (1) month of the expected revenue from sale of electricity at the prevailing tariffs;

minus

Amount held as security deposits under clause (a) and clause (b) of sub-section (1) of Section 47 of the Act from consumers except the security deposits held in the form of Bank Guarantees:

Provided that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up;

(b) Interest shall be allowed at a rate equal to the State Bank Base Rate (SBBR) /1year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) / any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable as on 1st April of the financial year in which the Petition is filed plus 250 basis points:

Provided that at the time of truing up for any year, interest on working capital shall be allowed at a rate equal to the weighted average State Bank Base Rate (SBBR) / 1 year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) / any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable prevailing during the financial year plus 250 basis points. "

9.11.2 The Discussion Paper while comparing the working capital requirement norms of various SERCs suggested to continue with the provision of Receivables for 1 month net of consumer security deposits (in cash) as GERC's existing working capital norms are already quite stringent, whereas, in other SERCs it is either 45 days or 2 months. It was also suggested to deduct the revenue received from pre-paid consumers, as it is received in advance by the Utilities.

Suggestion/Comment on Stakeholders:

1) In regard to working capital norm of distribution supply business MUL has submitted that existing norms are already stringent as compared to other states, thus same may be retained.

Maintenance Spare:

2) MUL has submitted that in case assets are being built by consumers/developers by its own cost and is being handed over to the Distribution Licensee to maintain the same, hence it should be added while calculating Maintenance Spares which is 1% of GFA.

3) GUVNL has submitted that DISCOMS are required to keep inventory for comparative small value items to large numbers. This requires longer inventory holding period for making available maintenance spare all the time. Other SERCs are also allowing maintenance spare at 1% of GFA. Therefore, the norms for maintenance spare is reasonable and may be reviewed further.

Receivables:

4) GUVNL submitted that as per the provisions of GERC Supply Code, consumers are allowed to make payment with 10 days from the date of billing by DISCOMs. Further, DISCOMs are required to give notice of 15 days to consumers before effecting disconnection of power supply. Thus, it takes almost 45 days to recover the billed amount from consumers and around 55 days for effecting disconnection of power supply considering the same as noted on the discussion paper, other SERCs have allowed receivables equivalent to 2 months billing amount for computation of working capital.

5) TPL submitted that based on billing cycle, actual recovery takes minimum 45/ 50 days in case of monthly billing cycle and 75 days

in bimonthly cycle. Therefore, the receivable component allowed for working capital should be 60 days.

Commissions View:

9.11.3 The Commission has considered above suggestions/objection of stakeholders. Further, it is observed that the GERC's existing working capital norms are already quite stringent. Accordingly, the Commission is of view to continue with prevailing provisions with slight modification as proposed below:

"38.5 Retail Supply of Electricity

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

(i) Operation and maintenance expenses for one month; plus

(ii) Maintenance spares at one (1) per cent of the opening Gross Fixed Assets; plus

(iii) Receivables equivalent to one (1) month of the expected revenue from sale of electricity at the prevailing tariffs; minus

(iv) Average monthly collection from Prepaid Consumers; minus

(v) Amount held as security deposits under clause (a) and clause (b) of sub-section (1) of Section 47 of the Act from consumers except the security deposits held in the form of Bank Guarantees:

Provided that for the purpose of Truing-up, the Receivables shall be computed based on the actual revenue from sale of electricity net of revenue from pre-paid consumers;

Provided further that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up before sharing of gains and losses."

9.12 Fuel and Power Purchase Price Adjustment (FPPPA).

9.12.1 The GERC MYT Regulation, 2016, includes the FPPPA mechanism for recovery of variation power purchase cost. However, it doesn't specify any formula to recover the difference between actual power purchase cost and base power purchase cost. Further, the Commission vide its Order dated 29 October, 2013 in Case No. 1309/2013 and 1313/2013, has approved the detailed formula for FPPPA (Fuel and Power Purchase Price Adjustment) to recover the difference between actual power purchase cost and base power purchase cost approved by the Commission.

9.12.2 Further, in the above stated Order, the Commission had directed the distribution licensees to approach the Commission for the prior approval along with FPPPA charge computation, if in case, increase in FPPPA in any quarter is beyond ten (10) paise per kWh. The Commission has also directed that the FPPPA calculations shall be submitted to the Commission within one month from the end of the relevant quarter and same has to be published in the Licensee's website.

9.12.3 FPPPA formula approved by GERC in Order dated 29 October 2013 in Case No. 1309/2013 and 1313/2013 is as follows:

"FPPPA = [(PPCA-PPCB)]/ [100-Loss in %]

Where

'PPCA' is the average power purchase cost per unit of delivered energy (including transmission cost), computed based on the operational parameters approved by the Commission or principles laid down in the power purchase agreements in Rs./kWh for all the generation sources as approved by the Commission while determining ARR and who have supplied power in the given quarter and transmission charges as approved by the Commission for transmission network calculated as total power purchase cost billed in Rs. Million divided by the total quantum of power purchase in Million Units made during the quarter.

'PPCB' is the approved average base power purchase cost per unit of delivered energy (including transmission cost) for all the generating stations considered by the Commission for supplying power to the company in Rs./kWh and transmission charges as approved by the Commission calculated as the total power purchase cost approved by the Commission in Rs. Million divided by the total quantum of power purchase in Million Units considered by the Commission.

'Loss in %' is the weighted average of the approved level of Transmission and Distribution losses (%) for the four DISCOMs / GUVNL and TPL applicable for a particular quarter or actual weighted average in Transmission and Distribution losses (%) for four DISCOMs / GUVNL and TPL of the previous year for which true-up have been done by the Commission, whichever is lower."

9.12.4 The Discussion Paper suggests adoption of the Fuel and Power Purchase Adjustment Surcharge (FPPAS) formula mentioned in the Rule 14 of Electricity (Amendment)

Rules, 2022 notified Ministry of Power, Government of India on 29 December, 2022.

Suggestion/Comment on Stakeholders:

1) GUVNL has submitted that the clause 14 of the Electricity Rules, 2022 provides that the appropriate commission shall within 90 days of publication of these, rules, specify a price adjustment formula for recovery of the costs. Arising on account of the variation in the price of fuel. or power purchase costs and the impact in the cost due to such variation shall be automatically passed through in a consumer tariff, on monthly basis. using this formula and such monthly automatic adjustment shall be trued up on annual basis by the appropriate Commission. Thus, the formula provided in the Rule (Annexure) is to be made applicable only in the cases where the State Commission has not specified the formula in respect State owned DISCOMs. However, the Commission vide order dated 29.10.2013 has already prescribed the FPPPA formula for computation and recovery of FPPPA charge on per unit basis from various category of consumers. As per the methodology, the FPPPA charges is to be computed on quarterly basis. The FPPPA formula approved by the Commission is simple, easy to implement and ensures recovery of incremental Power Purchase Cost in a prudent and reasonable manner. Thus, in order to ensure simplicity and ease of implementation, GUVNL has requested to continue with the formula prescribed by the Commission for computation of FPPPA charges.

2) FOKIA has suggested that detail including the FPPAS calculation and recovery shall be published on its website and archive the same through a dedicated web address.

3) In regard to FPPPA computation, Prayas Energy Group has submitted following submission:

    a) Variation in inter-state transmission charges should only be considered, not in intra-state transmission charges. This is because intra-state tariff determination coincides with the tariff process for DISCOMs.

    b) It is not clear if the new methodology will have FPPPA as a percentage of the billed amount or whether the 5% threshold for automatic passthrough is 5% of the billed revenue or the category-wise ABR. This should be clarified. Treatment of categories where the revenue includes subsidies should also be clarified.

    c) The rules imply that regulatory vetting could take place during the true-up process. Since fuel costs form a substantial part of total costs, vetting of periodic filings by the Commission is essential. In fact, explicit approval should be necessary from the Commission each time the amount for recovery exceeds a pre-specified threshold/cap for recovery in a month. This is particularly critical if the price increase is substantial and could lead to tariff shock in subsequent months.

d) Any cost impact due to decisions of courts or tribunals should be recovered only after explicit regulatory approval is awarded for recovery of the cost. Further, such costs should be reported separately and clearly in each FPPPA filing by the DISCOM.

e) The carrying cost for carry-forward, under-recovery and over-recovery should be similar.

f) In case of negative FPPPA, the amount should be deposited into an FPPPA stabilization fund which can be used to offset positive FPPPA in other months and reduce tariff volatility and impact on consumers. In order to ensure transparency in reporting of utilisation of such a fund, details of the fund and changes to the fund should be separately reported in FPPPA filings of the DISCOMs.

g) During every tariff process, the base average tariff should be adjusted by the fuel surcharge being charged so as to reflect revenue recovery from consumers.

Commissions View:

9.12.5 The Ministry of Power, Government of India, vide Rule 14 of Electricity (Amendment) Rules, 2022 notified on 29 December, 2022 has issued detailed formula for computation of FPPAS (Fuel and Power Purchase Adjustment Surcharge). Further, Ministry of Power, Government of India vide Electricity (Amendment) Rules, 2023 in notification dated 30 June 2023 has notified amendment in above state formula. Accordingly, following formula is proposed to be included in the draft MYT Regulations:

"115. Fuel and Power Purchase Adjustment Surcharge (FPPAS)

115.1. Computation of FPPAS:

(a) For these Regulations "Fuel and Power Purchase Adjustment Surcharge" (FPPAS) means the increase in cost of power, supplied to consumers, due to change in Fuel cost, power purchase cost and transmission charges with reference to cost of supply approved by the Commission.

(b) FPPAS shall be calculated and billed to consumers, automatically, without going through regulatory approval process, on a monthly basis, according to the formula, prescribed by the Commission in these Regulations, subject to true up, on an annual basis:

Provided that the automatic pass through shall be adjusted for monthly billing in accordance with these Regulations;

Provided further that the Distribution Licensee shall make quarterly submissions of the detailed FPPAS computations, duly supported by the documentary evidences, justifying such computations, along with details its charging and recovery from the consumers.

(c) *FPPAS shall be computed and charged by the Distribution Licensee, in (n+2)th month, on the basis of actual variation, in cost of fuel and power purchase and Interstate Transmission Charges for the power procured during the nth month. For example, the FPPAS on account of changes in tariff for power supplied during the month of April of any financial year shall be computed and billed in the month of June of the same financial year:*

Provided that in case the Distribution Licensee fails to compute and charge FPPAS within this time line, except in case of any force majeure condition, its right for recovery of costs on account of FPPAS shall be forfeited and in such cases, the right to recover the FPPAS determined during true-up shall also be forfeited.

(d) *The Distribution Licensee may decide, FPPAS or a part thereof, to be carried forward to the subsequent month in order to avoid any tariff shock to consumers, but the carry forward of FPPAS shall not exceed a maximum duration of two months and such carry forward shall only be applicable, if the total FPPAS for a Billing Month, including any carry forward of FPPAS over the previous month exceeds twenty per cent of variable component of approved tariff.*

(e) *The carry forward shall be recovered within one year or before the next tariff cycle whichever is earlier and the money recovered through FPPAS shall first be accounted towards the oldest carry forward portion of the FPPAS followed by the subsequent month.*

(f) *(f) In case of carry forward of FPPAS, the carrying cost calculated on simple interest basis at the rate of one year SBI MCLR or any replacement thereof by SBI from time to time being in effect applicable for 1 year period, as applicable prevailing during the relevant year shall be allowed till the same is recovered through tariff and this carrying cost shall be trued up in the year under consideration.*

(g) *Depending upon quantum of FPPAS, the automatic pass through shall be adjusted in such a manner that,*

i. *If FPPAS ≤ 5%, 100% cost recoverable of FPPAS by Distribution Licensee shall be levied automatically using the formula.*

ii. *If FPPAS > 5%, 5% FPPAS shall be recoverable automatically as per item (i) of sub-paragraph (g) above. 90% of the balance FPPAS shall be recoverable automatically using the formula and the differential claim shall be recoverable after approval by the Commission during true up.*

(h) The revenue recovered on account of pass through FPPAS by the Distribution Licensee, shall be trued up later for the year under consideration and the true up for any financial Year shall be completed by 30th June of the next financial year.

(i) In case of excess revenue recovered for the year against the FPPAS, the same shall be recovered from the Distribution Licensee at the time of true up along with its carrying cost to be charged at 1.20 times of the carrying cost rate approved by the Commission and the under recovery of FPPAS shall be allowed during true up, to be billed along with the automatic FPPAS amount.

Explanation:- *For example in the month of July, the automatic pass through component for the power supplied in May and FPPAS, if any, recoverable after true up for the month of April in the previous financial year, shall be billed.*

(j) The Distribution Licensee shall submit such details, in the stipulated formats, of the variation between expenses incurred and FPPAS recovered, and the detailed computations and supporting documents, as required by the Commission, during true up of the normal tariff.

(k) To ensure smooth implementation of the FPPAS mechanism and its recovery, the Distribution Licensee shall ensure that its billing system is updated to take this into account and a unified billing system shall be implemented to ensure that there is a uniform billing system irrespective of the billing and metering vendor through interoperability or use of open source software as available.

(l) The Distribution Licensee shall publish all details including the FPPAS formula, calculation of monthly FPPAS and recovery of FPPAS (separately for automatic and approved portions) on its website and archive the same through a dedicated web address.

(m) Formula for Computation of FPPAS:

$$Monthly\ FPPAS\ for\ Nth\ Month\ (\%) = \frac{(A-B)*C\ +\ (D-E)}{\{Z\ *\ (1-\ Distribution\ losses\ in\%/100)\}\ *\ ABR}$$

Where,

Nth month means the month in which billing of FPPAS component is done. This FPPAS is due to changes in tariff for the power supplied in (n-2)th month

A is Total units procured in (n-2)th Month (in kWh) from all Sources including Long-term, Medium-term and Short-term Power purchases (To be taken from the bills issued to Distribution Licensees)

B is bulk sale of power from all Sources in (n-2)th Month. (in kWh) = (to be taken from provisional accounts to be issued by State Load Dispatch Centre by the 10th day of each month).

C is incremental Average Power Purchase Cost (including the change of fuel cost) = Actual average Power Purchase Cost (PPC) from all Sources in (n-2) month (Rs./ kWh) (computed) - Projected average Power Purchase Cost (PPC) from all Sources (Rs./ kWh)- (from tariff order)

D = Actual inter-state and Intra-State Transmission Charges in the (n-2)th Month, (From the bills by Transcos to Discom) (in Rs)

E = Base Cost of Transmission Charges for (n-2)th Month. = (Approved Transmission Charges/12) (in Rs)

Z = [{Actual Power purchased from all the sources outside the State in (n-2) th Month. (in kWh) (1 – Interstate transmission losses in % /100) + Power purchased from all the sources within the State(in kWh)}*(1 – Intra-State losses in %) – B]/100 in kWh*

ABR = Average Billing Rate for the year as approved by the Commission (in Rs/kWh)

Distribution Losses (in %) = Target Distribution Losses as approved by the Commission

Inter-state transmission Losses (in %) as approved by the Commission

Note:

The Power Purchase Cost shall exclude any charges on account of Deviation Settlement Mechanism.

Other charges which include Ancillary Services and Security Constrained Economic Despatch shall not be included in Fuel and Power Purchase Adjustment Surcharge and adjusted though the true-up approved by the Commission.”

10 Guidelines for Capital Expenditure Approval Framework (Annexure III)

10.1 Background

10.1.1 The Gujarat Electricity Regulatory Commission (GERC) is mandated with the task of regulating the electricity sector within the state of Gujarat. The Commission aims to balance the interests of consumers and regulated entities. Annexure III provides guidelines for the approval of Capital Investment Schemes have been formulated to provide a comprehensive framework for the approval of capital expenditures in the electricity sector.

10.1.2 The Commission has the power under Section 181 of the Electricity Act, 2003, to make regulations consistent with the Act and the rules to carry out the provisions of the Act. The Commission has endeavored to bring out the best possible regulatory framework through these guidelines.

10.1.3 The electricity sector is capital-intensive, requiring significant investment for infrastructure development, maintenance, and upgrades. Over the years, the power sector has undergone significant changes, including technological advancements, increased power consumption, and the entry of private players. These changes have led to new challenges and opportunities. Also, these investments have a direct impact on the quality of service and the tariffs charged to consumers. Therefore, it is essential to have a well-defined regulatory framework to ensure that such investments are prudent, justified, and result in the most cost-effective solutions for both the utilities and the consumers.

10.2 Development of the Guidelines and core principle of the Capital Investment Approval process:

10.2.1 The Commission has drawn upon its experience and existing regulations in other states, particularly the Maharashtra Electricity Regulatory Commission (MERC), Delhi Electricity Regulatory Commission (DERC) to draft these regulations. The objective is to optimize capital investment through an improved framework for prudence checks.

10.2.2 These guidelines establishes a structured process for evaluating and approving capital investment projects proposed by regulated utilities. These guidelines mandates that any capital investment exceeding threshold amount (as per type of utility) must receive prior approval from the Commission.

10.2.3 The Commission will grant final approval for capital investments during the True-up phase, which follows the scheme's implementation. This approval is contingent on a thorough review and verification of various factors, including the actual costs incurred, materials used, and the scheme's proper execution. Additionally, all necessary legal clearances, such as environmental and electrical permissions, must be in place.

10.2.4 These guidelines aim to optimize capital investment through an improved framework for prudence checks. By ensuring that only necessary and justified capital expenditures are approved, the Commission aims to minimize any undue impact on tariffs. The regulations will also provide a transparent mechanism for the utilities to pass on the legitimate costs to the consumers while safeguarding against any unjust enrichment.

10.2.5 Further, these guidelines also provide for Transmission Licensees and Distribution Licensees to prepare, update and maintain Standard Cost Sheet for all capital items procured by them based on latest rates discovered through competitive bidding or latest Board approved standard rates on an annual basis, These Standard Cost Sheet shall be the reference document for estimation of item-wise capital cost by the Applicant while seeking in-principle approval of DPR Scheme

11 Guidelines for Allocation of Assets and Cost in Distribution Business (Annexure V)

11.1 Background

11.1.1 Section 62 of the Electricity Act, 2003 requires determination of tariff for wheeling of electricity and retail sale of electricity separately by the SERCs, which essentially requires segregation of costs of distribution between wheeling and retail supply. Regulation 87 of the GERC MYT Regulations, 2016 provides that the Wheeling Charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business. despite the continued emphasis of the Commission on separation of the accounting of wires related costs and supply related costs, which is required to move towards greater competition in the retail supply business, as well as determination of true wheeling charges, there is little or no initiative by the Distribution Licensees for segregation of expenses between the Wire Business and Retail Supply Business.

11.1.2 Therefore, in the Discussion Paper, , following time-bound actions were proposed:

a) Commission to issue guidelines for segregation of accounts of Distribution Licensee between Wires Business and Retail Supply Business in next 6 months;
b) Distribution Licensees to undertake the preparatory work for segregate their accounts of Wires Business and Retail Supply Business in next 6 months;
c) Distribution Licensees to submit their respective audited and certified separate accounts for Distribution Wires Business and Retail Supply Business from the next financial year onwards, i.e. year 2 of the new MYT Control Period, which shall become the basis for determination of wheeling and retail supply ARRs and hence the determination of wheeling charges;
d) Distribution Licensees not able to provide audited and certified separate accounts for Distribution Wires Business and Retail Supply Business, shall continue to segregate the expenses of Distribution Business based on the 'Allocation Matrix' provided in the MYT Regulations. However, in such case, the rate of return on Equity shall be reduced to the base rate / reduced by 1.00% from the normal rate of return of Equity.

11.1.3 Accordingly, while issuing draft GERC MYT Regulations, 2023, the Commission has also proposed "Guidelines for Allocation of Assets and Cost in Distribution Business" as Annexure V.

11.2 Development of the Guidelines

11.2.1 The objective of these guidelines is to establish frameworks for asset categorization and cost allocation in distribution businesses. Gross Fixed Assets (GFA) and related cost to be divided among EHT, HT, LT, and Supply Business for segregating Wheeling and Retail Supply ARR.

11.2.2 These guidelines are to be followed in the steps as below:

1) **Allocation of assets:** The Fixed Assets of the Distribution Licensee's to be classified in following three groups.

(i) **Supply Function**- All Assets related to consumption analysis and audit, billing and payment facilities such as IT hardware and software for consumption analysis, billing, etc., cash collection centers, automated payment kiosks, consumer care centers, etc.

(ii) **Common to Business Function** - those assets and facilities that cannot be earmarked either to Wires business or to Supply business. e.g. Administrative office buildings, Furniture and fixtures, electrical and electronic appliances and security systems, etc. used in various administrative offices, Common Vehicles, Common to business IT software and hardware, communication facilities, etc.

(iii) **Wires Function**- After identification and exclusion of Supply dedicated and Common to Business assets, the remaining assets of the Distribution Licensees shall be classified under Wires dedicated function.

2) **Formation of purpose-based asset bundles for wires function:** The assets dedicated to Wires function as identified shall be divided into three groups:

(a) **Voltage identifiable** i.e. those assets that clearly and specifically pertain to a single voltage class;

(b) **Boundary Assets** that exist along the boundary of two voltages i.e. power transformers and distribution transformers which serves more than one voltage and

(c) **Common Voltage** assets that belong to network (wires) business but are not specific to any voltage level and can be utilized across all or multiple voltage levels within the network

3) **Identification / allocation of defined wire asset groups over different voltages:** The three groups of wire assets are decided above are given a basis of allocation over different voltage.

4) **Allocation of Common Assets (as allocated to Wires function) over different voltage levels:** This step covers the methodology for allocation of common assets to Wires and Supply functions using the ratio of Wires only and Supply only assets to total (Wires + Supply only) assets. Further, the Common Assets so allocated to Wires

function shall be further allocated to different voltage levels of distribution.

5) **Determination of various asset ratios and allocation of wires cost components to different voltage levels and supply cost:** Based on the allocation of assets as discussed in preceding steps, the entire GFA of distribution can be divided between EHT, HT, LT voltages (Wire Business) and Supply Business. The values so allocated therein will result in different asset ratios obtained for Network Asset Group, Non-network Asset Group and Total Assets. The assets ratio will be determined which will be considered as base for allocation of cost of ARR of Wire business.

   Based on the asset values at different voltage levels, the various cost elements of Distribution Wires ARR shall be determined.

11.2.3 The Commission is of the view that these Guidelines may be referred for a methodical segregation of Wire and Retail Supply Business as against the existing methodology of applying pre-specified allocation matrix. The objective of these Guidelines would be that each Distribution Licensee shall be filing its Wires ARR segregated into the different voltage levels of EHT, HT and LT. The Commission understands that segregation of regulatory accounts between Wire and Supply Business would take some time, and therefore, has proposed that the Distribution Licensee shall maintain segregated accounting records for the Distribution Wires Business and Retail Supply Business by the third year of Control Period and till then Aggregate Revenue Requirement of the Distribution Licensee shall be apportioned between Wheeling Business and Retail Supply Business in accordance with the Allocation Matrix provided in these Regulations.