Forum of Regulators (FOR)

Study report on Ceiling Tariff for Distribution Sector

Assisted by:

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Abbreviations

ABR	Average Billing Rate
ACOS	Average Cost of Supply
ARR	Aggregate Revenue Requirement
CERC	Central Electricity Regulatory Commission
CTU	Central Transmission Utility
DISCOM	(Electricity) Distribution Company
FAC	Fuel Adjustment Charge
FOR	Forum of Regulators
FPPPA	Fuel and Power Purchase Price Adjustment
MYT	Multi Year Tariff
NTI	Non-Tariff Income
OA	Open Access
O&M	Operation and Maintenance
PPC	Power Purchase Cost
SERC	State Electricity Regulatory Commission
ST	Short Term
STU	State Transmission Utility

Executive Summary

The Electricity Act 2003 allows for multiple parallel licensees in the same supply area and provides for determination of a ceiling tariff by the Appropriate Commission in such cases. The Tariff Policy also suggests that the State Electricity Regulatory Commissions (SERCs) may consider price cap regulation and that the Forum of Regulators should evolve a comprehensive approach in this regard.

In this context, FOR commissioned a study on Ceiling tariff for distribution sector in India. The study seeks to propose a framework for implementing ceiling tariffs for retail electricity sale in India's distribution sector. Accordingly, this report presents a comprehensive examination of the legal/ policy/ regulatory framework for retail electricity tariffs, a review of related national and international case studies and discusses various options for implementing ceiling tariffs in electricity distribution sector of India.

Electricity tariffs in India are determined by SERCs for the Distribution Companies (DISCOMs) in their respective jurisdictions, as per powers granted under the Electricity Act 2003 and using a 'Performance Based Cost of Service' approach – as laid out in The Tariff Policy notified by the Government of India. As per 'Cost of Service/ Cost Plus' approach, tariffs are set by the Regulatory Commissions to reflect actual costs incurred by the power utilities.

In the past, an instance of ceiling tariff was observed when in 2007, JSERC approved Jharkhand State Electricity Board's (JSEB) tariff, as ceiling for JUSCO[1] (with a parallel power distribution license in Seraikela-Kharsawan District of Jharkhand), till its own tariff was determined by JSERC in 2010.

Presently in States with multiple State owned DISCOMs like Odisha, Gujarat, Rajasthan, Uttar Pradesh, Madhya Pradesh, Haryana, Odisha, Karnataka, Andhra Pradesh, Telangana etc., SERCs maintain uniform electricity tariffs for the entire State i.e. the same retail tariff applies to consumers of all DISCOMs in the State. Uniform tariffs are maintained by SERCs either by way of adjustment in bulk power purchase cost of the DISCOMs or by calculating the revenue surplus/ deficit on a consolidated basis for DISCOMs in the State.

Multiple parallel licensees exist in the city of Mumbai, where Tata Power Company - Distribution (TPC-D) holds a distribution licence to supply electricity in parallel to Adani Electricity Mumbai Limited (AEML[2]) and BEST in their respective supply areas. Post series of litigations, TPC-D's right to distribute electricity in Mumbai through a parallel licence was established. TPC-D was allowed to use network of other utilities for supplying electricity and a protocol for consumer migration was established by MERC, to avoid duplicity of network with additional cost burden on consumers. However, MERC determines tariffs separately for AEML, TPC-D, BEST and MSEDCL through separate tariff orders, and there is no uniform tariff across the City/ State.

International Review

International case studies show that with multiple suppliers competing with each other, electricity suppliers often set their tariff rates based on market forces, below a regulator-determined ceiling tariff. From the review of these international case studies, two alternative approaches emerge for calculation of ceiling tariffs, Bottom-Up approach and Top-Down approach. A Bottom-Up approach is essentially Cost Plus approach, calculated as sum of all prudent costs incurred for supply of power. The Top-Down approach on the other hand, sets tariff based on benchmarking or average of available tariff rates offered by various utilities/ suppliers.

[1] now known as Tata Steel Utilities and Infrastructure Services Limited
[2] formerly RInfra-D or BSES

In the United Kingdom, the Domestic Gas and Electricity (Tariff Cap) Act of 2018 requires the regulator Ofgem to set a limit on the rates charged by the suppliers for electricity and gas supply to a certain type of domestic customers. Ofgem employs a bottom-up or cost-plus methodology to establish the Ceiling Tariffs. Ofgem sets the level of the cap based on a broad estimate of how much it costs an efficient supplier to provide gas and/or electricity services to a customer. The Tariff Cap is updated every quarter (3 months), reflecting changes in underlying costs and inflation.

In Australia, the Australian Energy Regulatory (AER) determines a Default Market Offer (DMO), as the maximum price (or 'price cap') that a retailer can charge a customer on a standing offer. The DMO is set with an objective to protect customers from unjustifiably high prices, while allowing retailers a sufficient margin to enable them to recover costs and offer new products and customer innovations to the market. AER in its first DMO order for 2019-20, determined the tariff cap using a 'Top-Down' Approach, as the mid-point or 50th percentile between a range of lower and upper bound tariffs offered by various retailers.

Ceiling Tariffs in Indian Context

In Indian context, various variables such as long-term PPAs, cost-plus approach for tariff determination, single DISCOM in a licence area, etc. need to be factored in appropriately while developing a framework for ceiling tariff. It is to be noted that the ceiling tariff in case of countries such as Australia, UK, etc. were introduced in the context of retail competition in supply of power. However, till such time retail supply competition is introduced in India's power sector, or multiple or parallel distribution licensees do not exist, Ceiling Tariffs may be implemented as a price cap for the DISCOMs, seeking to induce efficiency in operation of such DISCOMs.

The Ceiling Tariffs may be set using a Cost-Plus or Bottom-Up method, as the efficiency aspects differ significantly across States and DISCOMs. The Top-Down approach is more suitable for competitive markets with multiple suppliers. Under Cost-Plus approach, the components of Ceiling Tariffs may include Cost of Power, Network Costs and Operating (Supply) Costs.

In the current power sector structure, while Ceiling Tariff shall be calculated by adding up all cost components i.e. Cost of Power, Network Cost and Operating (Supply) Cost, the component which shall remain relevant from the perspective of ceiling (and where efficiency aspects could be relevant) is the Operating (Supply) Cost portion. The remaining portions of the costs i.e. Cost of Power and Network Cost may continue to be determined by the Regulatory Commissions annually/ periodically and continue to remain pass-through for any variations on actual basis, for the time being.

The Operating Cost (Supply) portion for Ceiling Tariffs, may be determined by Regulatory Commissions only once at the beginning of a Control Period (but separately for each year of the Control Period) or once every few years, without any true-up for cost variations. Since no true-up is to be performed for this portion of cost, a headroom may be allowed for any unforeseen/ uncontrollable cost variation.

Once sufficient data is available for benchmarking with respect to determination of Ceiling Tariffs, the same could be modified to address the challenges and concerns which may arise during implementation. Also, when the retail supply competition is introduced, the Regulatory Commissions may gradually include other cost components under the purview of supply companies (such as cost of power) under the ceiling mechanism along with adequate benchmarks or headroom as may be required. The principles for calculating the Ceiling Tariffs may remain the same i.e. on a cost plus basis, but additional benchmarks may be used by the Regulatory Commissions for determining each individual cost component – for instance, with sufficient deepening of wholesale power market and reduced share of long-term bilateral PPAs in power procurement mix, the Cost of Power may be determined basis price trends on wholesale power markets.

Also, shift to top-down approach could be considered once sufficient competition is implemented in the power markets and consumers have options for choosing from multiple suppliers.

Describing Ceiling Tariffs

Various approaches for formulating and calculating ceiling tariffs in India have been explored in this report, drawing insights from the national and international case studies. The approaches discussed in the report include options such as fixed price cap determined by the SERCs or tariffs indexed to movement in underlying costs or a default common tariff for all consumers, with calculations based on either normative costs or an average/%tile of existing tariff schedules of DISCOMs or basis consumer paying capacity.

Basis detailed discussion on pros and cons of these various options, the Ceiling Tariffs are described as follows:

*Ceiling Tariffs may be described as a **maximum Average Billing Rate (ABR)** that may be charged to various **consumer categories** in the **State or a particular area**, during the **Control Period** as per tariff regulations, determined by the Appropriate Regulatory Commission using **normative or approved costs as per tariff regulations**.*

Methodology for computation of Ceiling Tariff

Under current power sector structure, on a cost-plus basis the Ceiling Tariffs may be determined as follows, so as to reflect fair costs of serving consumers:

1. Cost of Power

- Power acquisition cost from various sources as approved by SERC in its MYT/ Tariff Orders based on the existing PPAs of the DISCOMs in the State and as per approved energy mix.
- Weighted average for all DISCOMs in the State.
- Adjusted for approved network losses by the CERC/ SERC.
- The SERC may pass through in ceiling tariffs any prudent variations in cost of power, through FPPPA/ FAC charges and through annual true-up exercise.

  Note: In case there do not exist multiple DISCOMs to calculate weighted average cost, the Commission may take other suitable reference rates (for instance Power Exchange), in line with international experience such as UK, as per their prudence.

2. Network cost:

- The network costs shall comprise of:
  - Inter-State Transmission or CTU charges, as published by NLDC
  - Intra-State Transmission or STU charges, as approved by respective SERC
  - Distribution Wheeling charges, as per approved Wheeling ARR (basis allocation norms or segregated accounts) by SERC
- In case of multiple licensees in the State, the weighted average wheeling charge of all DISCOMs in the State (basis their energy sales) may be considered. Or, in case of parallel licensees, wheeling charges of DISCOM with most expansive network may be considered in ceiling tariffs.
- The SERC may pass through the actual network costs in ceiling tariffs, through annual tariff order/ true-up exercise.

3. Operating cost (supply)

- This shall cover costs related to retail supply activities such as metering, billing, collection and other commercial activities.

- Where segregated ARR for supply business is available, Operating Cost (Supply) may be taken as supply business ARR less Power Purchase Cost (PPC), divided by approved energy sales. Where segregated ARR is not available, Operating Cost (Supply) may be estimated as total ARR of the DISCOM, less PPC, less transmission charges, less Wheeling charge for Open Access multiplied by approved energy sales.

- Weighted average of all DISCOMs (basis their energy sales) in State may be considered for Operating Cost (Supply). If parallel licensees exist in a DISCOM's area, the Commission may include their operating costs as well in the weighted average. However, any smaller utility with disproportionately high per-unit costs due to a smaller consumer base, maybe excluded.

4. Headroom Margin:

- Drawing from the international experience , in addition to the judicious costs determined by the Regulator in its MYT or Tariff Order, an extra buffer may be permitted in the Operating Cost (supply), in the form of a headroom margin.

- It is envisaged that the Regulator may calculate Operating Cost (Supply) for Ceiling Tariffs only once at the beginning of a Control Period (but separately for each year of the Control Period) or once every few years, without any true-up for cost variations. Hence a headroom may be allowed for such unforeseen costs in the Operating Cost (Supply) portion of the ceiling tariffs.

- This Headroom shall also act as a margin for competition among multiple DISCOMs/ suppliers. DISCOMs may improve their operational efficiency and keep operating cost (supply) below ceiling, to enjoy higher returns.

- The Regulator may take a prudent call on the level of headroom to be allowed in Ceiling Tariffs, based on variation between MYT approved costs and Trued-up or Actual Costs, in recent past.

Applicability of Ceiling Tariffs

- The sum of cost components forming part of Ceiling Tariffs, may be converted into consumer category wise ABR, within a limit of ±20% i.e. 80% to 120%. DISCOMs may set tariffs below this ceiling.

- Further Ceiling Tariffs may be applied by SERCs on a State-wise basis, or may be determined separately for a specific area with say multiple parallel licenses in the same area of supply (where costs are significantly different than other DISCOMS in the State).

SERCs may use this suggested methodology as broad principles for determination of ceiling tariffs. The model indicated under the study is suggestive in nature and the State Commissions may refine it based on the conditions prevailing in their respective States.

Way Forward

In order to effectively enable ceiling tariffs, account segregation of DISCOMs into wheeling and supply business shall be required, to accurately determine the network and operating costs. Also, once supply and network business are segregated and only ceiling is determined for the supply business, the impact of distribution losses (higher or lower than approved targets) would also have to be segregated into network and supply business. Further rationalization of cross subsidy within

±20% in line with Tariff Policy, may be required to ensure tariffs remain below or equal to the ceiling. SERCs may also conduct detailed analysis for DISCOMs in their respective States/ region to calculate an appropriate level of headroom allowance in ceiling tariffs.

SERCs may first determine the ceiling tariffs, along with start of next control period for power distribution utilities in the State. In future, once retail supply competition is introduced, the ceiling may be determined for entire supply side cost of the business, including cost of power. This is assuming that power markets would have developed sufficiently by then to enable suppliers to manage their costs.

1. Introduction

1.1.1. The Forum of Regulators (FOR) has been constituted in 2005 by the Government of India in terms of Section 166 (2) of the Electricity Act, 2003. The Forum consists of Chairperson of the Central Commission as Chairperson of the Forum and the Chairpersons of the State and Joint Electricity Regulatory Commissions as Members of the Forum. Secretarial assistance to the Forum is provided by the Central Commission. The Forum is responsible for harmonization, coordination and ensuring uniformity of approach amongst the Electricity Regulatory Commissions across the country, in order to achieve greater regulatory certainty in the electricity sector.

1.1.2. One of the functions discharged by FOR is to assist its members to evolve measures for protection of interest of consumers and promotion of efficiency, economy and competition in power sector. Tariff related reforms in power distribution is one of the key areas that impacts the overall sector's operational efficiency and viability.

1.1.3. Electricity tariffs in India are determined by State Electricity Regulatory Commissions (SERCs) for the power distribution companies (DISCOMs) falling under their jurisdiction, in accordance with Section 62 of the Electricity Act 2003. The Electricity Act empowers SERCs to set tariffs for retail sale of electricity, while being guided by the Tariff Policy.

1.1.4. The Electricity Act 2003 also provides a framework for competition among distribution licensees, through the concept of multiple parallel licensees in the same area of supply. The Act also provides for determination of a ceiling tariff by the Appropriate Commission, in such cases of two or more distribution licenses in the same area.

1.1.5. Further the Government of India has been evaluating various options for introduction of competition in retail sale of electricity, to provide consumer choice and to use competition for fostering improved service delivery. It has been observed in several international case studies that post implementation of retail competition, electricity suppliers set their own tariff rates based on prevalent market forces, below a ceiling tariff set by the regulator in some cases.

1.1.6. With this context, the objective of this study is to suggest a framework for implementation of ceiling tariffs for the retail sale of electricity in the distribution sector in India.

1.1.7. The scope of the study involves detailed study of the relevant legal, policy and regulatory framework, review of national and international case studies to evolve possible options for implementation of ceiling tariffs in Indian context.

2. Legal & Policy review

2.1. Electricity Act 2003

2.1.1. Electricity tariffs in India are determined based on the provisions contained in the Electricity Act 2003 and Tariff Policy 2016 notified by the Government of India.

2.1.2. Section 61 read along with Section 86 of the Electricity Act 2003, empowers State Electricity Regulatory Commissions (SERCs) to issue regulations and determine tariffs for power distribution utilities.

'Section 61. (Tariff regulations): The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff….'

'Section 86. (Functions of State Commissions): The State Commission shall …. Determine the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail …'

2.1.3. Further, Section 62 of the Electricity Act 2003, provides for determination of ceiling tariffs for retail sale of electricity by the SERC, wherein two or more distribution licensees are operating in same area.

'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: …..
(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.'

2.1.4. Each SERC[3] issues tariff regulations individually for their respective State, basis their due diligence and State specific considerations. In doing so the SERCs are guided by:

- Electricity Act 2003
- Policies, such as Tariff Policy, National Electricity Policy, etc.
- CERC regulations
- Model regulations by Forum of Regulators (FOR)

2.1.5. In accordance with the above, SERCs determine tariffs for distribution/ supply of electricity by DISCOMs in their respective States/ jurisdictions, using a 'Performance Based Cost of Service' approach – as laid out in Tariff Policy (first issued in 2006 and amended in 2016).

2.2. Tariff Policy, 2016

2.2.1. The Tariff Policy, issued by Government of India in 2006 and amended in 2016, outlines the overall framework for setting of electricity tariffs in India. Section 5.11 of the Tariff Policy

[3] Or Joint Electricity Regulatory Commission (JERC) in case of State of Goa and UTs

2016 provides for a 'Performance Based Cost of Service' regulation to be followed for determination of electricity tariffs.

> *'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.'*

2.2.2. As per 'Performance Based' approach, the parameters used to build up Annual Revenue Requirement (ARR) of a utility are classified as Controllable and Uncontrollable items. Further as per 'Cost of Service/ Cost Plus' approach, tariffs are set by Regulatory Commissions to reflect actual costs incurred by the power utilities. Annual Revenue Requirement (ARR) of utility/ project is determined by the Regulatory Commission, by adding up various costs incurred.

2.2.3. Section 5.11 a) of the Tariff Policy, also suggests that SERCs may consider price cap regulation. The provision of Tariff Policy further states that Forum of Regulators should evolve a comprehensive approach in this regard.

> *'5.11 a) ….. The State Commission may also consider price cap regulation based on comprehensive study. The Forum of Regulators should evolve a comprehensive approach in this regard. The considerations while preparing such an approach would, inter-alia, include issues such as reduction in Aggregate Technical and Commercial losses, improving the standards of performance and reduction in cost of supply.'*

2.3. National Electricity Policy, 2005

2.3.1. The National Electricity Policy 2005 (hereinafter referred to as NEP 2005), issued by the Government of India, also allows for multiple distribution licenses in the same area, under section 5.4.7. The NEP 2005 requires SERCs to regulate tariffs including connection charges, to ensure that DISCOMs do not resort to cherry picking by demanding unreasonable charges from consumers.

> *'5.4.7 One of the key provisions of the Act on competition in distribution is the concept of multiple licensees in the same area of supply through their independent distribution systems. State Governments have full flexibility in carving out distribution zones while restructuring the Government utilities. For grant of second and subsequent distribution licence within the area of an incumbent distribution licensee, a revenue district, a Municipal Council for a smaller urban area or a Municipal Corporation for a larger urban area as defined in the Article 243(Q) of Constitution of India (74th Amendment) may be considered as the minimum area. The Government of India would notify within three months, the requirements for compliance by applicant for second and subsequent distribution licence as envisaged in Section 14 of the Act. With a view to provide benefits of competition to all section of consumers, the second and subsequent licensee for distribution in the same area shall have obligation to supply to all consumers in accordance with provisions of section 43 of the Electricity Act 2003. The SERCs are required to regulate the tariff including connection charges to be recovered by a distribution licensee under the provisions of the Act. This will ensure that second distribution licensee does not resort to cherry picking by demanding unreasonable connection charges from consumers.'*

2.3.2. Further section 5.8.6 of NEP 2005 also states that private sector participation should be facilitated in the sector and that competition which will determine the price rather than any cost plus exercise on the basis of operating norms and parameters.

'5.8.6 Competition will bring significant benefits to consumers, in which case, it is competition which will determine the price rather than any cost plus exercise on the basis of operating norms and parameters. All efforts will need to be made to bring the power industry to this situation as early as possible, in the overall interest of consumers.'

2.4. Other Relevant Rules

2.4.1. The 'Electricity (Rights of Consumers) Amendment Rules, 2023' envisage implementation of Time-of-Day tariffs for consumer categories in electricity pricing. These rules mandate that Time-of-Day tariffs should not be less than 1.20 times the normal rate during peak hours for Commercial and Industrial (C&I) consumers with a maximum demand of more than 10 kW and 1.10 times for other consumers, excluding agriculture once smart meters have been installed. The Time-of-Day Tariff applies to the energy charge component of the normal tariff, and the duration of peak hours are to be determined by the State Commission or State Load Despatch Centre. These provisions shall be suitably considered while designing the tariff schedule for ceiling tariffs.

2.4.2. Also the Ministry of Power (MoP) through its notification dated 9-Nov-2021 envisaged pass through of fuel and power procurement costs into retail electricity tariffs to ensure the viability of the power sector. This rule allows for the pass-through of costs from Generation Companies (GENCOs) to Distribution Companies (DISCOMs) and ultimately to consumers.

3. National and International Case Studies

3.1. National Review

Uniform Tariffs among DISCOMs within a State

3.1.1. In States with multiple State owned DISCOMs like Odisha, Gujarat, Rajasthan, Uttar Pradesh, Madhya Pradesh, Haryana, , Karnataka, Andhra Pradesh, Telangana etc. SERCs maintain uniform electricity tariffs for the entire State i.e. same retail tariff applies to consumers of all DISCOMs in the State.

3.1.2. Basis review of SERC tariff orders, two types of approaches are observed that are adopted by SERCs to maintain uniform electricity tariffs within the State:

- **Adjustment in bulk power purchase cost:** In States like Odisha and Gujarat, power is purchased collectively for all DISCOMs in the State, by a single entity. The cost of power procurement of each DISCOM from that single entity is adjusted based on the paying capacity of the respective DISCOMs (mix of sales across consumer categories or average billing rate) to ensure DISCOM's revenue from retail tariffs are sufficient to meet its Revenue Requirement.
- **Consolidated Surplus/ (Gap) for DISCOMs:** In States like Bihar and Haryana, SERC calculates surplus/ (gap) of ARR for DISCOMs on a consolidated basis i.e. combined revenue of all DISCOMs in the State is matched against combined Revenue Requirement of DISCOMs. Each DISCOM then has its own individual loss/ deficit, which the Government may fund through subsidy or loss takeover.

JUSCO Ceiling Tariffs

3.1.3. Tata Steel Utilities and Infrastructure Services Limited (formerly known as Jamshedpur Utilities and Services Company Limit–d - JUSCO), operates 2 power licenses in Jharkhand - one at Jamshedpur and another at Seraikela-Kharsawan District. JUSCO had been managing power distribution functions for the city of Jamshedpur since 1923. Subsequently, in December 2006 JUSCO was granted a parallel power distribution license at Seraikela-Kharsawan District in Jharkhand.

3.1.4. In 2007, JSERC approved Jharkhand State Electricity Board's (JSEB) tariff, as ceiling for JUSCO, till its own tariff is determined. The Commission issued an order dated October 16, 2007 on the ARR & tariff petition of JUSCO, stating that:

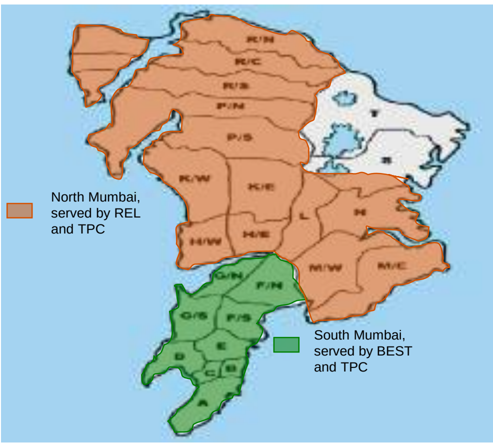
> *'Since two distribution licensees JUSCO and JSEB are operating in the same area (i.e. Saraikela-Kharsawan), for immediate operation of the distribution licensee JUSCO, we approve the maximum ceiling of the retail tariff as approved for the JSEB in terms of the proviso of Section 62(1)(d) of the Electricity Act, 2003. Within the aforesaid maximum ceiling of tariff the licensee JUSCO shall propose its own tariff for approval of the Commission within 15 days from the receipt of the order. The tariff shall be reviewed after four months, on receipt of required relevant details/information with reference to our regulations and its profit/loss will be taken into count in the next tariff period.'*

3.1.5. JSERC issued the first tariff order for JUSCO separately in Jan-2010, for period FY 2009-10, post which JSEB's tariff ceased to be JUSCO's ceiling.

Mumbai Parallel Licensee

3.1.6. In the Mumbai region of the Maharashtra State, four distribution licensees i.e. BEST, Adani Electricity Mumbai Limited (formerly RInfra-D or BSES), MSEDCL (limited to few suburbs) and Tata Power Company (TPC-D) hold the licence to distribute electricity within the areas specified in their respective licences.

Figure 1: Mumbai - DISCOM license area



3.1.7. While BEST, AEML and MSEDCL operate within specific distribution licence areas allocated to them, distinct from each other, TPC-D, on account of its historical background and the Supreme Court judgment delivered on 8-Jul-2008, is licensed to distribute power in the entire Mumbai region excluding select area served by AEML and excluding all the areas served by MSEDCL.

3.1.8. Historically, TPC-D supplied power to bulk users (1000 KVA and above) in Mumbai, by virtue of its four individual licenses - Bombay (Hydro-electric) license of Mar 1907, Andhra Valley (Hydro-electric) license of Apr 1919, Nila Mula Valley License of Nov 1921 and Trombay Thermal Power Electric license of Nov 1953. After the amalgamation of he Tata Hydro-Electric Power Supply Company Limited and the Andhra Valley Power Supply Company Limited with Tata Power, the Government of Maharashtra on July-2001 transferred the said 1907 license, 1919 license and the 1953 license to Tata Power. RInfra has a licence for distribution of energy in the suburban area of Mumbai. This licence was initially issued on 13.05.1930 to the BSES Limited which was subsequently renamed as Reliance Energy Limited and then renamed as Reliance Infrastructure Limited Distribution (RInfra-D).

3.1.9. In 2002, RInfra-D filed a petition with Maharashtra Electricity Regulatory Commission (MERC) complaining of encroachment by TPC within its area of supply. MERC in its order concluded that TPC-D's license did allow it to distribute electricity in RInfra territory "for all purposes including supply to other licensees for their own purposes and in bulk". However, it cautioned that such an unfettered right to distribute electricity worked against MERC's ability to regulate the licensees in an efficient, economic and equitable manner and contradicted the objective of competition, efficiency and economy. Therefore, it directed the two companies to recruit a consulting company to study the issues. The adoption of the report of the consulting company, it said would be determined after a public hearing.

3.1.10. Both licensees filed separate appeals against this MERC order before the Appellate Tribunal for Electricity (APTEL). The Appellate Tribunal through its judgment dated 22-May-2006, set aside the MERC's order and held that the TPC under its license was entitled to supply energy only in bulk and not in retail. Appeals were filed by TPC and others against this APTEL judgment. Finally, the regime of parallel distribution licensees in Mumbai was ushered in vide a landmark Supreme Court judgment dated 8 July 2008 whereby the apex court upheld Tata Power's contention that it was a universal supplier in Mumbai and could distribute power to any retail consumer in the city. Regarding RInfra's contention that not having a distribution network in place, TPC was not in a position to supply energy to any consumer, the Supreme Court stated that it could use RInfra's network to wheel power to its consumers, given the overall intent behind the Electricity Act 2003 being to promote competition.

3.1.11. Subsequently, on 20-Aug-2008, the Commission notified the MERC (Specific Conditions of Distribution Licence applicable to The Tata Power Company Limited) Regulations, 2008, effectively confirming TPC-D as a distribution licensee for the entire city of Mumbai, covering the licence areas of both BEST and RInfra-D

3.1.12. As per the Hon'ble Supreme Court's judgment as well as the Capital Investment approval guidelines 2005 laid down by the MERC, TPC-D submitted a Network Rollout Plan of Rs. 1062 Crores to the State Commission, in which it proposed a network roll out for the period FY 2009-10 to FY 2011-12. The State Commission in its Order dated 15.06.2009 in Case No. 113 of 2008 did not approve the investment proposal of Network Rollout Plan and directed Tata Power for "exploring" the use of the wires of other distribution licensees.

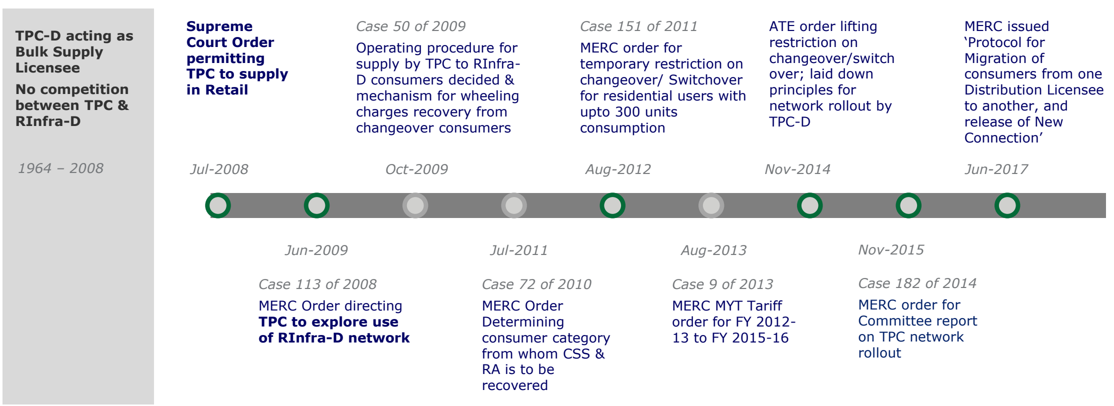
3.1.13. TPC- D and R Infra-D entered into discussion to effect supply to changeover consumers. These discussions culminated into MERC order dated 15-Oct-2009, in which it issued an interim arrangement for consumers opting for changeover of supply from one licensee to other licensee through the network of the existing licensee.

3.1.14. In 2011, RInfra-D filed a petition with MERC, accusing TPC-D of cherry picking and laying down its own network only in select areas with high end consumers of RInfra – with an objective to avoid payment of cross subsidy surcharge and a share of Regulatory Assets. On the other hand, TPC-D claimed that RInfra-D unilaterally withdrew from Joint Meter Reading (JMR) activity and was causing inconvenience to consumers. Against this petition, MERC passed its order on 22-Aug-2012 and directed TPC-D to focus all its energies in rolling-out its own network in eleven identified clusters within a period of 1 year, to enable it to supply its existing and prospective consumers. Further, MERC directed that TPC-D should ensure that wide publicity is given to reach the consumers in these identified 11 Clusters, to the effect that TPC-D is in a position to provide supply using its own network to all consumers interested in taking power supply from TPC-D. The order also restricted consumer changeover from RInfra-D to TPC-D only for the residential consumers who consume electricity upto 300 units a month, for a period of one year.

3.1.15. This order of MERC was appealed by TPC-D and RInfra-D in APTEL. The APTEL in its judgment dated 28-Nov-2014, laid down certain principles on the subject of network rollout by TPC-D, stating that parallel network should be established only to those areas where laying down of parallel network will improve the reliability of supply and benefit the consumers. APTEL also directed MERC to decide a detailed protocol of consumer switchover/ changeover.

3.1.16. A Committee was formed through the MERC's notification dated 03-Dec-2015 to further address and finalise the operational specifics of TPC-D's network roll-out plan and provide recommendations on protocol and procedure in terms of which any migration of consumers shall take place, among other objectives. Based on the recommendations of the Committee, the Commission in its order dated 12-Jun-2017 issued the 'Protocol for Migration of consumers from one Distribution Licensee to another, and release of New Connection'.

Figure 2: Mumbai Parallel License - Timeline of key developments



3.1.17. Presently, MERC determines tariffs separately for AEML (formerly RInfra-D or BSES), TPC-D, BEST and MSEDCL through separate tariff orders. Each of these tariff order, adheres to same principles/ methodology set under the MERC's MYT Regulations. Unlike other States with multiple DISCOMs like Madhya Pradesh, Rajasthan etc., tariff of each utility in Maharashtra is different on account of different cost levels of the utilities, and there is no uniform tariff across the State.

3.1.18. The Commission determines three part tariffs for each utility – Fixed monthly charges, per unit energy charges and per unit wheeling charges. In order to calculate separate wheeling charges, the Commission's MYT Regulations require utilities to maintain separate accounting records for the Distribution Wires Business and Retail Supply Business. Consumers changing over from AEML to TPC-D, while remaining connected through the network of AEML, are required to pay wheeling charges of AEML, fixed plus energy charges of TPC-D and a cross subsidy surcharge to AEML.

3.1.19. Tariff differential between AEML and TPC-D can cause consumers to migrate among DISCOMs. This may lead to conflicts among the utilities, specially when tariffs are determined by regulator and are not under direct control of utilities themselves. In a recent case, TPC-D approached APTEL asking for stay on high tariff hikes approved by MERC in its order dated 31-Mar-2023 for TPC-D for FY2023-24. Generally a higher tariff could have meant higher revenues for the utility had there been only a single DISCOM, but in case of Mumbai with AEML and TPC-D competing for consumers, a higher tariff would have resulted in outward migration of consumers to other utility. The APTEL, in its order dated 13-Jul-2023, provided relief to TPC-D by granting an interim stay on the tariff schedule of FY2023-24 and directed to revert to previous tariff schedule approved in MYT order dated 30-Mar-2020, till the disposal of this appeal. Subsequently, vide Order dated 05-Jan-2024, the APTEL directed MERC to pass a fresh Tariff Order considering that FY2023-24 was drawing to a close. In view of the direction, MERC issued an Order dated 23-Feb-2024 stating that the previous Tariff Schedule approved in MYT Order dated 30-Mar-2020 shall continue to apply for FY 2023-24 until such time Tariff Order for FY2024-25 is issued.

3.1.20. Accordingly, in areas like Mumbai with multiple parallel licenses, ceiling tariffs may be implemented, allowing to set their own tariffs basis prevalent market forces. This shall help in dispelling concerns of utilities related to consumer migration due to unfavourable tariff determination. This may be further be coupled with enabling reforms such as cross subsidy reduction and liquidation of any outstanding regulatory assets, to prevent cherry picking among utilities due to loading of these costs on consumers.

3.2. International Review

United Kingdom

3.2.1. In 1990, consumers with more than 1 MW demand were free to contract with any supplier, but all other consumers had to buy from their local Regional Electricity Company (REC), which had a franchise monopoly. In 1994, the franchise limit was lowered to 100 kW. Full competition was introduced into Britain's electricity retail market in 1999.By mid-1999 the REC franchises finally ended. Since then domestic and non-domestic consumers have been able to shop around for their electricity supplier.

3.2.2. Between 2000 and 2002, the Office of Gas and Electricity Markets (Ofgem) lifted all price controls on gas and electricity, considering that competition had sufficiently developed and that a separate Competition Act was introduced in Mar 2000. Price controls were removed in a phased manner – first for direct debit customers and then for standard credit customers.

3.2.3. However the UK Competition and Market Authority (CMA) in its report 'Energy Market Investigation: Final Report' dated 24-Jun-2016, found that lack of consumer engagement with the energy market gave suppliers market power over customers, which suppliers were then able to exploit through their pricing practices.

3.2.4. This paved way for the Domestic Gas and Electricity (Tariff Cap) Act 2018. The Act provides for the imposition of a cap by Ofgem on rates charged to domestic customers for the supply of gas and electricity in United Kingdom.

3.2.5. As per the Act, the Tariff Cap should take into consideration following matters:

- The need to create incentives for holders of supply licences to improve their efficiency
- The need to set the cap at a level that enables holders of supply licences to compete effectively for domestic supply contracts
- The need to maintain incentives for domestic customers to switch to different domestic supply contracts
- The need to ensure that holders of supply licences who operate efficiently are able to finance activities authorised by the licence

3.2.6. The Tariff Caps aim to protect consumers who are on Standard Variable[4] or Default Tariffs[5] from overpaying for their energy bills. Standard variable or Default Tariffs are often more expensive than fixed-term tariffs, and customers who do not actively switch suppliers or negotiate better rates may end up paying more for their energy.

3.2.7. The Domestic Gas and Electricity (Tariff Cap) Act of 2018, gives Ofgem (United Kingdom's energy sector regulator) the responsibility to modify the standard supply license condition so that tariff cap conditions can be imposed on all standard variable rate and default rate.

3.2.8. Accordingly, Ofgem modified Standard Licence Condition (SLC) 28AD, namely the conditions which impose a cap on all standard variable and default rates that may be charged by the holders of supply licences for the supply of gas or electricity under domestic supply contracts. These are referred to as 'the tariff cap conditions'.

3.2.9. Ofgem sets the level of the cap based on a broad estimate of how much it costs an efficient supplier to provide gas and/or electricity services to a customer. The Tariff Cap is updated every quarter (3 months), either reflecting changes in underlying costs or increases in inflation.

Proposed methodologies by Ofgem for setting Tariff Cap

Before setting the first tariff cap in November 2018, the Ofgem in its consultation paper discussed following methodologies for calculating the cap:

1. **A market basket of tariffs:**
   - This approach proposed to set the cap using an average of market tariffs offered in the competitive segment of the market. It would use the prices of a selection of competitive tariffs, with some minimum criteria for inclusion.
   - This approach was ruled out by the Commission as it may not reflect the long-run costs of an efficient supplier, because of following reasons:
     - Market prices depend on suppliers' pricing strategies, and the degree and nature of competition in the market, not just their underlying costs. The cheapest tariffs in the market could be priced above or below the long-run

[4] *Standard variable Rate "means a rate or amount charged for, or in relation to, the supply of gas or electricity under the contract that is not fixed for a period specified in the contract"*

[5] *Default rate "means a rate or amount charged for, or in relation to, the supply of gas or electricity under the contract that applies if the customer under the contract fails to choose an alternative rate."*

costs of an efficient supplier because of the nature of competition in the market.

- Different suppliers may face different costs. A number of larger suppliers highlighted that smaller suppliers do not have the same regulatory costs or obligations to participate in certain social and environmental schemes. Also a number of suppliers noted that some suppliers might have a cost base which cannot be generalised to the market as a whole (for example, if a supplier focussed on niche products or services).
- When updating over time, basing the cap on market prices could affect suppliers' incentives to price keenly in the competitive segment. This could affect suppliers' pricing behaviour in the competitive segment in order to influence the next update of the cap level. This incentive could (over time) affect the extent to which market prices reflect the long-run costs of an efficient supplier.

2. Adjusted version of Safeguard Tariff:

- Safeguard Tariff is determined by Competition and Markets Authority (CMA) of UK. It caps the prices for select type of customers which include prepayment customers and households eligible to receive Warm Home Discount.
- Under this approach Ofgem proposed to adjust this Safeguard Tariff by differential costs for serving direct debit customers and some other adjustments suggested by stakeholders, to be set as tariff cap.
- CMA's Safeguard Tariff was based on the average price of two competitive mid-tier suppliers in 2015, with certain adjustments to account for differences between the cost base of the benchmark companies and the market more generally
- Some of the disadvantages noted by Ofgem of this approach was that two suppliers may be an inadequate sample size to represent an efficient level for an industry wide price cap, and that tariffs from 2015 were out of date.

3. Updated competitive price reference approach:

- Under this approach, Ofgem proposed to calculate tariff cap using broad methodology used by CMA for Safeguard Tariffs, but with more recent and revised price data - rather than rely on data from two suppliers in 2015.
- However, Ofgem noted that this method may not be able to treat new areas of uncertainty that requires Ofgem to make judgments that have not and cannot be tested by experience. As more adjustments are made to this method, it could become a less independent method and begin to evolve into a bottom-up cost assessment (discussed as next option).

4. Bottom-up cost approach:

- Under this approach, Ofgem proposed estimating efficient allowances for each cost category, and summing these together
- Ofgem noted that advantage of this approach compared with setting the cap using a competitive reference price, is that it gives additional clarity as to exactly which costs are included in the benchmark, and how each element of costs is being treated under the cap

> After evaluating pros and cons of each option, the Ofgem in its final decision, considered the Bottom-Up cost (or cost plus) approach as the most appropriate method for calculating Tariff Caps.

3.2.10. The Tariff Cap set by Ofgem consists of following cost components:

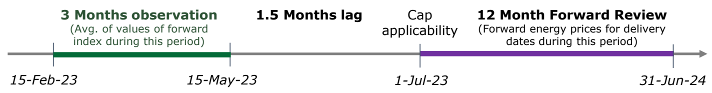
Figure 3: UK: Tariff Cap Components

3.2.11. The calculation methodology followed by Ofgem for these components and its sub-parts, is as follows:

Table 1: UK: Tariff Cap Components

Type	Name	Methodology
Wholesale (energy) Cost, WC	Direct Fuel Cost (DF)	Baseline cost based on Fuel Price Index (prices of forward energy products) as published by Independent Commodity Exchange Services (ICIS) This index price is further adjusted for: + Adjustment for allowances (for forecasting error etc.) + Adjustment for electricity losses + Backwardation cost: difference in cost due to mis-match in reference period (12 months) of index used and delivery period (3 months) + CfD[6] Allowance: cost incurred due to CfD scheme The Fuel Price Index is calculated by taking weighted average price of seasonal products (30:70 ratio for peak: baseload). The period of averaging is as follows: • 1.5 months lag: observation period ends 1.5 months before the price cap is set to begin i.e. for price cap beginning 1-Jul-2023, observation period ends on 15-May-2023 • 3 month observation period: index values averaged over 3 month period prior to end of lag date i.e. for price cap beginning 1-Jul-2023, the observation period runs from 15-Feb-2023 to 15-May-2023 • 12 month forward review: forward energy prices during the observation period, for delivery dates of 12 months from start of price cap i.e. for price cap beginning 1-Jul-2023, period of 1-Jul-2023 to 31-Jun-2024

[6] *The Contracts for Difference (CfD) scheme is the government's main mechanism for supporting low-carbon electricity generation. Under the CfD scheme, renewable generators receive a fixed price for their energy. Suppliers incur costs or benefits from the CfD scheme depending on whether there is a positive or negative difference between the wholesale price and this fixed price*

Type	Name	Methodology
		
	Capacity Market Cost (CM)	• This cost is allowed for capacity payments made by suppliers to generators. The cost is determined based on price discovered through auctions under Capacity Market Scheme as published by National Grid • The cost is divided by forecast total peak demand to derive an implied cost per peak MWh on the transmission system
Adjustment allowance, AA	Adjustment Allowance (AA)	• For debt-related costs resulting from COVID-19 - increase in working capital requirement and debt related administrative costs
Policy costs	Policy Cost (PC)	• Cost for supplier's environmental and social obligations for schemes like Renewable Obligation (RO), Feed-in-Tariff (FiT), ECO, Warm House Discount (WHD) and AAHEDC; determined by dividing cost incurred for each scheme with energy supplied
Network costs	Network Cost (NC)	Wheeling charges for: + **Transmission Network Use of System (TNUoS)**, for recovering cost of installing and maintaining transmission system; the cost is published by National Grid (operating as Electricity System Operator) annually in Pence/ Kwh, based on total allowed revenue determined by Ofgem (as per RIIO-ET2 for period 2021-2026) + **Distribution Use of System (DUoS)**, for recovering cost of installing and maintaining distribution system; the charge consists of a per unit variable charge and a per day fixed charge; the cost is published by each of the 14 individual Distribution Network Operators (DNOs)[7], based on total allowed revenue determined by Ofgem (as per RIIO-ED2 for period 2023-2028) + **Balancing Service Use of System (BSUoS)**, amount charged for the service of balancing the transmission system, such as running the national control room, frequency response arrangements, and other ancillary services and constraint costs – recovered on an ex-post basis; Forecasts of annual BSUoS charges, published by National Grid, are used as inputs
Operating costs	Operating Cost (OC)	• Baseline Cost, adjusted for Consumer Prices Index Including Owner Occupiers' Housing Costs (CPIH) • Baseline cost, includes: + Indirect costs + Depreciation and amortisation + Third party commissions for sales and marketing + Other obligatory industry charges, where these have been separated and are not captured elsewhere, etc. • Baseline cost, excludes:

[7] *By following Common Distribution Charging Methodology (CDCM) as per Distribution Connection and Use of System Agreement (DCUSA)*

Type	Name	Methodology
		– Energy Company Obligation/ Feed in Tariffs administration costs – Exceptional restructuring costs – Fines for non-compliance, etc. • Baseline costs are determined by Ofgem using Consolidated Segment Statements (CSS)[8] of various suppliers, and basis benchmarking exercise conducted among suppliers • Baseline costs for 1st Tariff Cap in 2018 was set using Bottom-Up approach, basis suppliers' historical costs and Ofgem's view on efficient level of these costs, as follows: – Calculated cost per customer account of various active suppliers – Calculated operating cost at total level, rather than breaking down into allowances for individual components of operating costs (eg metering, bad debt, customer service etc.) – Calculated cost as per the most recent financial year (i.e. 2017 for Tariff Cap, set in 2018) – Historical cost data of more than 60 suppliers active in market was used, excluding suppliers with customer base less than 250,000 or suppliers serving a niche customer base only or suppliers non-compliant on their license requirements – Based on the analysis of historical costs of suppliers, Ofgem determined an efficient level of operating cost as a benchmark between: ▪ 'Frontier Level' = average of the two lowest cost suppliers in sample ▪ Cost of lower quartile of companies in the sample
	Smart Metering Net Cost Change (SMNCC)	• Baseline Cost, adjusted for CPIH • Baseline cost reflects both trends in the direct charges to suppliers from industry bodies such as DCC and Smart Energy GB, as well as the expected impact of the rollout on industry metering and marketing costs
Payment Method Uplift Allowance, PA	Payment Method Adjustment Additional Cost (PAAC)	• Baseline Cost, adjusted for CPIH • Baseline cost reflects the additional debt and costs of supplying standard credit customers, including: + additional working capital costs + additional bad debt costs + additional administrative costs
EBIT	Earnings Before Interest and Tax Margin Percentage (E)	• Margins determined by Ofgem; set at 1.94% for latest period of Jul-Sep 2023

[8] *Ofgem require the large energy suppliers to produce audited annual CSS to show the costs, revenues and profits for the different segments of their generation and supply businesses*

Type	Name	Methodology
Headroom Allowance, HA	Headroom Allowance Percentage (H)	• Tariff Cap is set higher than estimate of the efficient benchmark costs i.e. the combined total of our estimates for each cost component. This is called additional allowance or “headroom”. • Headroom is allowance for any unidentified error or uncertainties, when: – Addressing the intrinsic uncertainty involved in estimating an efficient level of costs – Allowing efficient suppliers to manage volatile pass-through costs, particularly when purchasing energy – Helping with cost variation, because some efficient suppliers have costs that are higher or lower than average for reasons outside of their control (eg due to differences in their customer base) • This allowance for any unidentified error or uncertainties, is set at 1.46% by Ofgem; The % was back calculated from a £10 headroom allowance, determined in 1st price cap order of 2018; same % headroom allowance has been continued by Ofgem since then
VAT	Value Added Tax (VAT)	• As per prevalent tax rate

Source: Ofgem determinations and papers

RIIO Framework for Network Costs

Ofgem sets price controls for the companies that operate the gas and electricity networks in Great Britain by applying the ‘Revenue using Incentives to deliver Innovation and Outputs (RIIO)’ framework. Introduced in 2015 for electricity Distribution Network Operators (DNO), this framework replaced ‘Retail Prices Index less an efficiency savings estimate’ (RPI-X price controls). RIIO framework rewards companies that innovate and run their networks to better meet the needs of consumers and network users.

The fundamental construct of RIIO is same as RPI-X. Under the RIIO model the price control is set upfront for a fixed period of 8 years, using a building block approach. A baseline revenue is determined based on costs including expected efficient expenditure, allowance for taxation, capitalization and depreciation, regulatory asset value and WACC. Baseline revenues are adjusted for select uncertainty factors and indexation. Further, Incentives/ Penalties are provided in addition to baseline revenues basis performance of company on various output parameters.

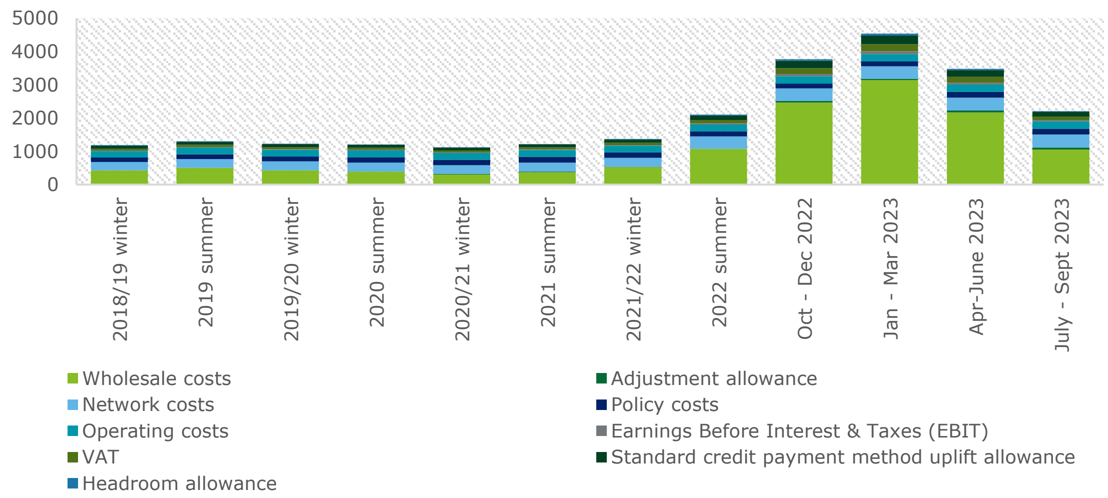
RIIO model defines outputs that network companies will be ‘held to account’ to deliver in return for earning revenue from consumers under the price control. Outputs are defined under six categories – Customer Satisfaction, Reliability and Availability, Safety, Conditions for Connections, Environmental Impact and Social Obligations. In each category, primary and secondary outputs are defined. Primary outputs reflect what customers of network services want delivered – such as Customer interruptions and customer minutes lost, while secondary outputs reflect objectives like network management and innovation.

3.2.12. The Tariff Cap is calculated by Ofgem, individually for:

- Each of the 14 regions in the country; and
- Two types of metering arrangements - Single Rate & Multi-Register Metering; and
- Three payment modes – Prepayment, Standard Credit and Other Payment Modes

3.2.13. The Tariff Cap determined by Ofgem, averaged for various regions of Great Britain, over the last 5 years is as follows:

Figure 4: UK: Tariff Cap trend (£ per household per annum)



Source: Ofgem; Note: Tariff Cap duel fuel including Electricity (2900 Kwh consumption annually, for Single Rate Meter) and Gas (12000 Kwh consumption annually) for Standard Credit payment mode

Australia

3.2.14. Full retail supply competition exists in all six regions of National Electricity Market (NEM) of Australia, allowing consumers to choose between competing retailers.

3.2.15. Two types of tariff schedules are available for customers to choose from – Market Offers and Standing Offers. Market offers are the tailored plans that energy companies advertise to attract customers. They can include discounts and different tariffs depending on people's circumstances. On the other hand, Standing Offers are intended to provide a safety net for customers who have not or cannot choose a Market Offer. All retailers are obliged to provide a Standing Offer.

3.2.16. Initially, retail prices were regulated; however, the price caps were set high and retailers were encouraged to compete below the cap. Victoria became the first state to abolish retail price regulation in 2009, followed by South Australia (2013), NSW (2014) and South East Queensland (2016).

3.2.17. However on 11-July-2018, the Australian Competition & Consumer Commission (ACCC) published a report 'Retail Electricity Pricing Inquiry (REPI) report'. In this report, the ACCC noted that high electricity prices and bills have placed enormous strain on household budgets and business viability. (ACCC) noted that standing offers, which were originally intended as a default protection for consumers who were not engaged in the market, were unjustifiably high and have been used by retailers as a high priced benchmark from which their advertised market offers are derived. The ACCC found that the standing offer is no longer working as it was intended and is causing financial harm to consumers.

3.2.18. To resolve this, among other recommendations, the ACCC suggested abolishing the current retail 'standing' offers (which are not the same between retailers) and replacing them with a new 'default' offer consistent across all retailers. ACCC further recommended that the Australian Energy Regulator (AER) be given the power to set the maximum price for the default offer in each jurisdiction.

3.2.19. Accordingly, as per Section 10 and Section 16 of The Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019, the Australian Energy Regulatory (AER) determines annually, a Default Market Offer (DMO) as the maximum price (or 'price cap') that a retailer can charge a customer on a standing offer in New South Wales (NSW), South

Australia (SA) and South-East Queensland (SE QLD). The Default market offer (DMO) came into effect on 1 July 2019.

3.2.20. In Victoria, the Essential Services Commission (ESC) regulates the state's energy, water and transport sectors. Like DMO, the ESC determines a Victorian Default Offer (VDO) annually for households and small businesses. Victorian Default Offer was introduced by the Victorian Government in a Governor in Council Order made under section 13 of the Electricity Industry Act 2000 (pricing order dated 30-May-2019). The first Victorian Default Offer was set in 2019 and came into effect on 1-Jan-2020.

3.2.21. The DMO/ VDO is set with an objective to protect customers from unjustifiably high prices, while allowing retailers a sufficient margin to enable them to recover costs and offer new products and customer innovations to the market. The DMO/ VDO is intended to be a service which all retailers in a non-price regulated distribution zone are obliged to offer customers that do not otherwise take up a market offer for the provision of electricity retail services.

3.2.22. The Default Tariffs are generally more expensive than the competitive deals retailers offer, or the 'Market Offers'. The Default Tariffs for each area also acts as a 'reference price' for residential and small business offers in that area. When advertising or promoting offer pricing, retailers must show the price of their offer in comparison to the DMO/reference price.

3.2.23. Australian Energy Regulatory (AER) in its first DMO order for 2019-20, determined the tariff cap using a 'Top-Down' Approach, using publicly available price information of market offers and standing offers of various suppliers.

3.2.24. As per this Top-Down approach, the DMO was set at mid-point or 50th percentile between a range of lower and upper bound as follow:

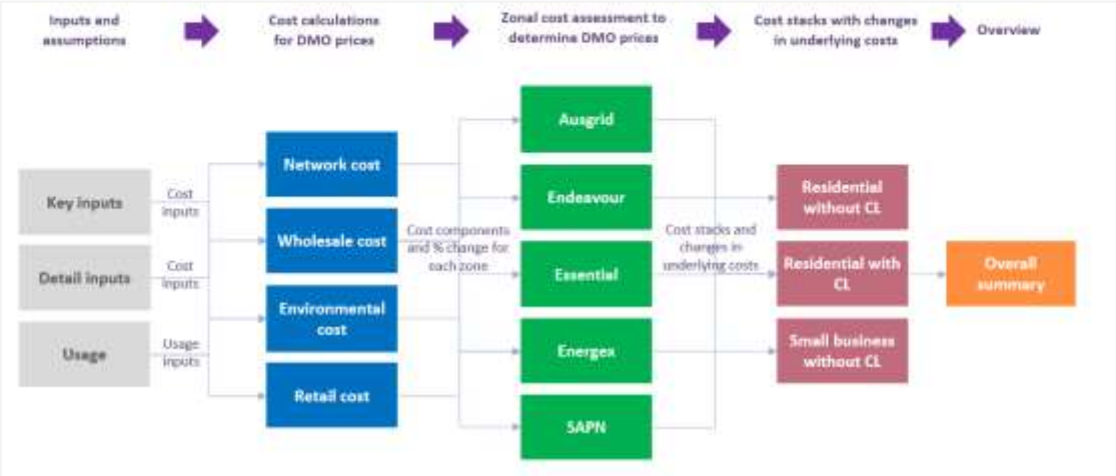
- Upper bound – Median of Standing Offers of all retailers in each distribution zone
- Lower bound – Median of unique Market Offers of all retailers in each distribution zone

Figure 5: Australia DMO: Top-Down approach

3.2.25. The key reasons for selecting this approach by the Regulator were:

- This price point would result in lower standing offer prices and provide price relief for affected customers, which is the key policy objective for introducing DMO prices
- This price point provides sufficient margin between the DMO price and more competitively priced market offer prices in each distribution zone such that there are still benefits for customers seeking out market offers that best meet their needs
- Median Market Offers are an indication of retailers' efficient costs. Higher than median Market Offers, allowed retailers to recover the efficient costs of providing services

3.2.26. The DMO cost is build-up as sum of costs as follows:



Source: AER's Default Market Offer 2022-23 – Final Determination – Cost Assessment Model

- **Wholesale costs:** costs retailers incur to purchase electricity in National Electricity Market (NEM). This cost is estimated through a separate study to forecast hourly load profiles for the year and spot prices in the market.
- **Network costs:** consists of 2 components:
  - Network Use of System (NUOS) charges: costs of providing transmission and distribution of electricity, as approved by AER under separate orders for annual network cost pricing using cost plus/ building block approach
  - Alternate Control Services (ACS) charges: costs of public lighting, ancillary network services (ANS) and installation/ maintenance of metering services
- **Environment costs:** cost incurred for procuring power from renewable sources under national schemes such as Renewable Energy Target (RET) or jurisdictional green schemes and costs to improve customer energy efficiency
- **Retail costs:** consist of following components:
  - Costs to serve: these costs include billing, call centres and hardship programs
  - Costs to acquire and retain customers: these costs include advertising campaigns and informing new customers of their options, rights and obligations
  - Advanced meter costs: retailers are responsible for managing the installation and ongoing costs of advanced meters
  - Bad and doubtful debt: retailers may set aside revenue to cover instances where customers cannot repay their electricity debt
  - Depreciation and amortisation: retailers may from time to time make up-front purchases and investments, such as software and IT system upgrades, which are depreciated over time.

3.2.27. For the draft determination of first DMO period 2019-20, the 'cost-stack' or percentage of each of the cost component in overall price, was calculated by first estimating the cost of each component in terms of per kWh price and then, using a set consumption amount, calculated the percentage of the cost component relative to a representative tariff. Cost information from 18 retailers covering six years of actual data was used for the analysis.

3.2.28. The DMO price cap is revised each year by the regulator and it comes into effect on July 1st each year. The baseline DMO cost is adjusted annually for changes in various cost factors.

The broad methodology adopted by the Australian Regulator for projection of these cost components in Default Market Offer (DMO) is as follows:

Table 2: Australia - Default Market Offer - Cost Components

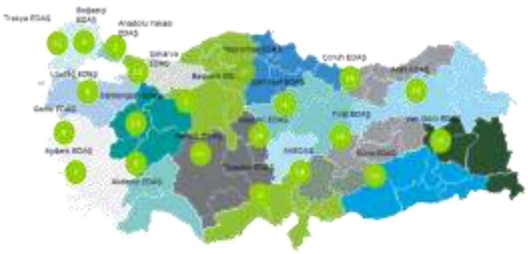
Component	Sub-Component	Methodology
Wholesale Cost	Wholesale Energy Costs (WEC)	• Wholesale energy costs are estimated based on market simulations to calculate expected spot market costs and volatility, and the hedging of the spot market price risk
	Other Wholesale Costs	• These include National Electricity Market (NEM) fees, ancillary services charges, Reliability and Emergency Reserve Trader (RERT) costs, AEMO direction costs, and costs of meeting prudential requirements
	Energy losses	• Distribution Loss Factors (DLF) for each jurisdiction and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the wholesale energy cost estimates to incorporate losses • MLFs and DLFs are published by AEMO annually
Environmental Cost	Large Scale Renewable Energy Target (LRET)	• Clean Energy Regulator (CER) publishes the Renewable Power Percentage (RPP), which requires power distribution companies to purchase Large-scale Generation Certificates (LGCs) • The estimated cost of compliance is derived by multiplying the RPP and the determined LGC price • The average LGC price is determined using a market based approach, that estimates forward prices for the two relevant compliance years
	Small Scale Renewable Energy Scheme (SRES)	• Similar to LRET, CER publishes the Small-scale Technology Percentage (STP), that translates into the required Small-scale Technology Certificates (STCs) to be purchased as a percentage of the estimated volume of electricity consumption • The cost of STC is taken as per CER's clearing house price for the year of default tariff determination
	Other environmental cost	• These include cost of compliance for other schemes such as New South Wales Energy Savings Scheme (ESS), New South Wales Peak Demand Reduction Scheme (ESS), South Australia Retailer Energy Productivity Scheme etc.
Network Cost	Network Use of System (NUOS) charges	• NUOS charge consist of following: – Network Access Charge – Energy Consumption Charge – Demand Charge – Capacity Charge • AER uses approved network tariffs as determined under separate tariff orders (for each regulatory control period for each distribution company) for calculation of DMO

Component	Sub-Component	Methodology
	Alternate Control Services (ACS) charges	• AER uses approved Alternate Control Services (ACS) charges as determined under separate tariff orders (for each regulatory control period for each distribution company) for calculation of DMO
Retail Cost	-	• Retail Costs include: – Cost to serve – Costs to acquire and retain customers – Depreciation Amortization – Advanced Meter cost – Bad & doubtful debt • AER determines the retail operating costs by applying Consumer Price Inflation (using RBA inflation) on baseline costs as published by Australian Competition Consumer Commission (ACCC) in its report 'Inquiry into the National Electricity Market'
	Retail allowance	• This encompasses retailer profit margin and an additional DMO retail allowance, to reflect a return on retailer risk, as determined by the Commission

Turkey

3.2.29. The power sector of Turkey includes 21 privatized power distribution companies, operating distribution network in their own geographical regions, with multiple retail supply companies in a region. Tariffs for distribution businesses and retail price caps are determined by Energy Market Regulatory Authority (EMRA).

Figure 6: Turkey - License area



3.2.30. Under the Price Equalization mechanism applicable in Turkey, the Regulator sets a uniform national tariff across the nation, with cross subsidy between DISCOMs to account for difference in distribution losses between regions. It is implemented with a view to protect the consumers partially or completely from the price differences arising from the cost differences among the distribution companies.

3.2.31. The difference between the regional revenue requirements and revenues from the national tariff is compensated through the price equalization mechanism. Each distribution company transfers the excess money collected to TETAŞ (wholesale trading company in Turkey) if the national tariff is higher than their cost reflective tariff. This excess money is transferred to the distribution companies, where national tariff is lower than their cost-reflective tariffs, thereby cross subsidizing them. This transaction is done monthly. The national tariff is set at a level sufficient to enable this transfer.

Philippines

3.2.32. Retail Supply Competition began in Philippines in 2013 with the introduction of Retail Competition and Open Access (RCOA). Initially consumers with load greater than 1 MW were considered contestable, i.e. given the right to choose their electricity retailer. After 2015, consumers above 750 kW of load were considered as contestable consumers, known as Phase II of RCOA. In the next Phase III beginning from 2021, the threshold for becoming a contestable consumer was further reduced to 500 kW. This part of the market is called 'Competition Retail Electricity Market (CREM)'.

3.2.33. Contestable Consumers are allowed to procure power from licensed Retail Electricity Suppliers (RES) or Local RES[9] of their choice. Energy Regulatory Commission (ERC) issues a Certificate of Contestability to qualified consumers based on rules of contestability. As on March 2023, there were 3163 contestable consumers and 47 RES in Philippines, as per ERC's Competitive Retail Electricity Market (CREM) Monthly Statistical Data report.

3.2.34. The RES are required to enter into a Retail Supply Contract with contestable consumers, clearly outlining under a Disclosure Statement, the applicable prices to be charged for electricity supply. The ERC does not regulate tariffs charged by RES to contestable consumers. However, ERC does determine Supplier of Last Resort (SOLR) Rates. A SOLR is an entity that provides Last Resort Supply to contestable customers who suddenly find themselves without a RES. Distribution Utilities (DU), serving non-contestable consumers, are designated as SOLRs in their respective franchised area. In case a DU is not capable of providing SOLR services, the ERC shall assign a neighbouring DU to serve as the SOLR.

3.2.35. The ERC determines the rates that can be charged by SOLR in accordance with its 'Rules for the Supplier of Last Resort (SOLR), 2006' and 'Rules on Rate Filling by the Supplier of Last Resort (SOLR), 2007'. In a competitive environment, this SOLR Rate may act as a ceiling rate, as there would be no economic rationale for a consumer to opt for RES supplying electricity at rates higher than SOLR rate.

3.2.36. The ERC determines SOLR Rate as sum of following:

- Competitive market-clearing Wholesale Electricity Spot Market (WESM) energy price during all hours of the period of SOLR service, as if the customer is buying energy directly from the WESM, or the bilateral contract price, whichever is higher;
- Premium to cover incremental administrative and overhead expenses
- Reasonable return for the SOLR
- All other applicable regulated charges, including Transmission charge and Distribution Wheeling Service charges

3.2.37. Even though ERC does not regulate tariffs for RES, it does determine the upstream costs of transmission wheeling rates and distribution wheeling rates (forming part of retail tariffs) using a cost plus approach under performance based regulations. Generation tariffs are un-regulated and are discovered through Wholesale Electricity Spot Market (WESM).

3.2.38. While determining these wheeling rates, to reduce the likelihood of price shocks to Customers, ERC defines a price cap or Maximum Allowed Revenue (MAR) for the transmission/ distribution utility. As per the Rules for Transmission Wheeling Rate (RTWR) and Rules for setting Distribution Wheeling Rate (RDWR), the Price Cap formula is defined as follows:

[9] *The difference between a RES and a Local RES in the Philippines is that a Local RES does not need a RES license. However, a Local RES must wait for a licensed RES to start marketing in its area. A RES must comply with all applicable Philippine laws and rules issued by the ERC. A Local RES is a non-regulated business segment of a distribution utility.*

$$MAR_t = [MAR_{t-1} \times \{1 + CWI_t - X\}] - K_t - RBR_t + PIS$$

Where,

t represents this year and t-1 represents previous year
MAR is Maximum Allowed Revenue (known as Maximum Allowed Price Cap in RDWR)
CWI is index of consumer prices
X is productivity or efficiency factor
K is correction for under/ over recovery of revenue in previous years
RBR is Related Business Revenue as per section 20 of EPIRA
PIS is a performance incentive for achieving specified targets

USA-Texas

3.2.39. Industry structure and regulatory framework of power sector varies from state to state in USA. Retail supply competition is allowed in 18 states of USA including state such as California, Texas, Illinois, Pennsylvania, New York, Washington DC etc. Some of the states suspended access to retail electricity choice after the California power crisis of 2000–2001.

3.2.40. In the state of Texas, retail supply competition was introduced with the passing of Texas passed Senate Bill 7 (SB7) in June 1999. As per the law, incumbent power utility ERCOT was given the responsibility of managing the networks business, while Retail Electricity Suppliers were allowed to supply power to consumers. Electric Cooperative areas and areas served by municipality owned electric utility were allowed to choose whether to introduce retail competition or not.

3.2.41. A major concern in implanting retail supply competition was that established energy providers would undersell to prevent competition with emerging retail energy providers. To prevent this, the SB7 established a price floor called 'Price to Beat'. A new Retail Energy Provider could charge rates that were lower than the 'Price to Beat', while existing providers had to offer rates that were equal to or above the 'Price to Beat'. This allowed new retail energy providers the time they needed to develop their business.

Key Takeaways from National & International Review

3.2.42. Basis review of national and international case studies, following key takeaways are identified for Indian context:

- Regulators in Australia and United Kingdom determine ceiling tariffs for consumers on default/ standing offers i.e. consumers who have not actively chosen any retail market offer of a supplier. In UK, the ceiling tariffs are determined by regulator using a bottom-up or cost plus approach. On the other hand in Australia, the regulator chose a Top-down approach for setting baseline ceiling tariffs, basis benchmarking of existing tariffs/ offers of active suppliers in the market. For Indian context, considering the lack of multiple suppliers in a supply area, a bottom-up or cost plus approach is more suitable.

- Taking cue from case studies of Australia and UK, the ceiling tariffs may comprise of components including network and supply charges. The network charges may be determined and passed through on actual basis as per tariff orders for the incumbent DISCOM – a practice already being followed by several states like Maharashtra, Telangana, Andhra Pradesh etc.

- In areas with multiple parallel licenses, like in Mumbai-India, differentials in tariffs can cause consumer migration from one utility to another. Utilities may allege tariffs determined by regulators for such migration. In such scenarios, ceiling tariffs shall help in dispelling concerns of utilities related to consumer migration due to unfavourable tariff determination.

4. Ceiling Tariffs in Indian Context

4.1.1. The distribution business in India is primarily non-competitive where DISCOMs are operated under a license from the Regulatory Commission. Prior to the Electricity Act 2003, the State Electricity Board under the respective State Government were undertaking the activity of distribution of electricity. Post the enactment of the Act, while commercial distribution entities under the holding of State Government were formed, they continued to retain the distribution of electricity in their area of supply.

4.1.2. Therefore, it becomes important to evaluate the methodology for ceiling tariff in the Indian context. In the previous Chapter a detailed international review has been undertaken regarding the procedure for fixation of ceiling tariff in countries including Australia, UK, etc. However, it is important to also take into consideration that the retail competition was already in place in such countries which enabled consumers to choose from multiple suppliers of electricity. However, the set-up in Indian power sector differs from such countries and has unique aspects such as long-term PPAs, single DISCOM in license areas, tariff based on cost plus approach, etc. which needs to be factored appropriately while developing a framework for ceiling tariff in India.

4.1.3. Therefore, till such time retail supply competition is not introduced in India's power sector, or we have multiple suppliers or parallel licensees in the licence areas, the Ceiling Tariffs can be implemented as a price cap for the DISCOMs to serve as an efficient price level under which to operate. However, the same should not act as a roadblock for new suppliers/ licensee and at the same time does not put the incumbent distribution company in a position where it is unviable to continue to supply to consumers of the specified area.

4.1.4. In line with the provisions of Tariff Policy for retail electricity tariffs, the ceiling tariffs may be calculated following a Cost Plus or Bottom-Up approach. A Top-Down approach is relevant for a competitive market and is therefore not suitable in current context of Indian power distribution sector, given the lack of multiple/ parallel distribution licensees in most of the states/ regions. Even in states like Gujarat, Bihar, Haryana etc. where more than one state owned DISCOMs exist, the cost structure of these DISCOMs is more or less similar with common power procurement undertaken through holding company or allocation of PPA and the tariff approved across the major distribution companies is common.

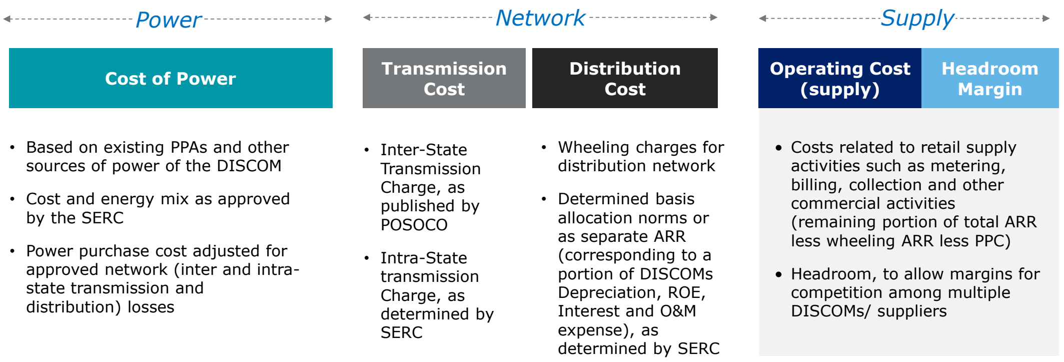
Figure 7: Possible methodologies for Ceiling Tariffs

Bottom-Up Approach	**Top-Down Approach**
Cost plus approach, as sum of all prudent costs incurred for supply of power	*Tariff based on benchmarking of available rates of various utilities*
• In line with Tariff Policy and tariff regulations issued by various SERCs • Gives clear indication of efficient costs that may be allowed in ceiling tariffs	• Relevant for a competitive market; not suitable in current context of Indian power distribution sector, given the lack of multiple/ parallel distribution licensees in most of the states/ regions • Even in states like Gujarat, Bihar or Haryana where more than one DISCOM

• Empowers SERCs to prudently analyse various costs elements, relevant to their state/ region	exist in the state, the cost structure of these DISCOMs is similar and does not offer a range of tariffs for assessment

4.1.5. On a cost plus basis, the Ceiling Tariffs may consist of following cost components, so as to reflect fair costs of serving consumers:

Figure 8: Cost components of Ceiling Tariffs



4.1.6. The cost of power purchase remains largely under long-term contracts and any short-term requirements are met through exchange or procurement through competitive bidding. Therefore, cost with respect to power procurement is required to be allowed based on the actual. The network cost which comprises of transmission and distribution cost would be appropriate to be considered as a pass through. Distribution network cost shall be required to be allowed as a pass through considering the shared nature of such infrastructure in case of multiple or parallel licensee.

4.1.7. Therefore, in context of the above cost structure, ceiling tariff may be relevant from the Operating (Supply) side portion of DISCOM's overall costs. It is to be noted that while Ceiling Tariff, shall be calculated by adding up all cost components i.e. Cost of Power, Network Cost and Operating (Supply) Cost, the component which is relevant from the perspective of ceiling (and where efficiency aspects could be relevant) is the Operating (Supply) Cost portion. The remaining portions of the costs i.e. Cost of Power and Network Cost may be continued to be determined by the Regulatory Commissions annually/ periodically and continue to remain pass-through for any variations on actual basis, for the time being.

4.1.8. In line with the framework, the Operating Cost (Supply) portion for Ceiling Tariffs may be determined by Regulatory Commissions for each year of the Control Period during the issuance of MYT Order. No revision or true-up on account of this Operating Cost (supply) may be allowed for the past year. Instead a headroom in form of a margin may be allowed to account for any unforeseen/ uncontrollable cost variation. Only under special circumstances such as change in law or force majeure, etc., warranting a revision of costs, the Regulatory Commission may review such headroom at the time of annual performance review / mid-term review for any significant changes in the cost parameters.

4.1.9. Once experienced is gained and sufficient data is available for benchmarking with respect to the current framework, the same could be modified to address the challenges and concerns which may arise. Also when the retail supply competition is introduced, the Regulatory Commissions may gradually include other cost components under the purview of supply companies (such as cost of power) also under the ceiling mechanism (i.e. with adequate benchmarks or headroom as the case may be). Therefore, the Regulatory Commissions may determine the overall Ceiling Tariffs to reflect the cost of supply by an efficient utility. While the principles for calculating the Ceiling Tariffs may remain same i.e. on a cost-plus basis, additional benchmarks may be used by Regulatory Commissions for determining each individual cost component. For instance, cost of power may be determined basis trend of price discovered on wholesale power markets or considering other factors such as rate of renewable power, markets rates during peak and off-peak hours, etc. This could be achieved when power markets would have deepened sufficiently and all suppliers would have flexibility to manage their power purchase costs through procurement from least cost options as against the existing system of procurement of power from long-term PPAs.

Note: Post introduction of retail supply competition, in case a portion of incumbent DISCOM's PPAs are allocated to new supply companies, the cost of such PPAs may have to be suitably allowed in the Ceiling Tariff calculations by the Regulatory Commissions, in addition to using wholesale market prices as benchmark. FOR's report on 'Roll out Plan for Introduction of Competition in Retail Sale of Electricity' suggests various approaches for allocation of PPAs among multiple suppliers, in proportion of their demand, with due consideration to age (remaining contract period) and cost of such PPAs.

4.1.10. Eventually in future, once sufficient competition exists in the retail supply market with multiple suppliers competing for consumers in a supply area, the Regulatory Commissions may also consider adopting a top-down approach for determination of ceiling tariffs, taking cue from international experience of Australia's Default Market Offer. Under such Top-Down approach, the Regulatory Commissions may use the prevalent tariff schedules offered by various suppliers to benchmark the ceiling. The benchmark could be set suitably by the Regulatory Commission as an average of all tariff schedules or as a certain percentile within the range of tariffs offered, serving as an efficient frontier for all suppliers.

Table 3: Mechanism for Ceiling Tariffs

Particulars	**Current scenario**	**Retail Supply Competition**
Sector Structure	*Single DISCOM in a license area*	*Multiple suppliers competing for consumers in an area*
Cost Components of Ceiling Tariff:		
• Cost of Power	Pass-though of cost variation	Ceiling with headroom
• Network Cost	Pass-though of cost variation	Pass-though of cost variation
• Operating (Supply) Cost	Ceiling with headroom	Ceiling with headroom

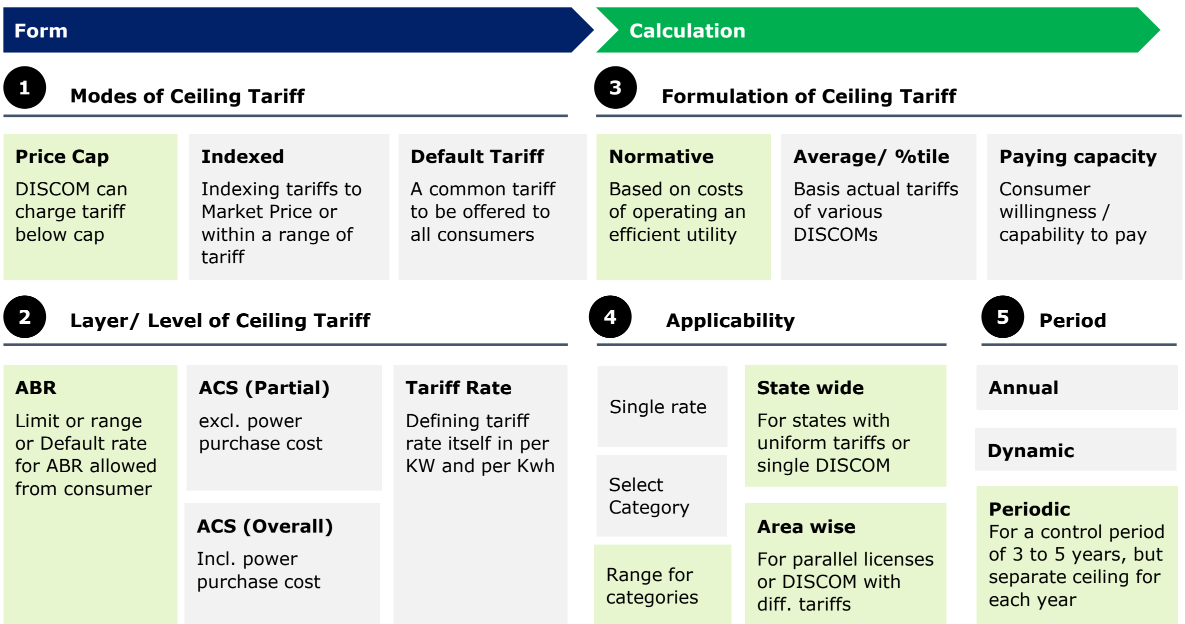
5. Describing Ceiling Tariffs

5.1.1. As discussed earlier in this report, while section 62 of the Electricity Act 2003 provides for calculation of 'maximum ceiling of tariff', no definition or structure for ceiling tariffs is defined in the current legal/ regulatory landscape of India's power sector.

5.1.2. There are several ways in which ceiling tariffs can be formulated and calculated in Indian context, taking cues from review of national and international case studies. For instance, ceiling tariffs may be calculated as a fixed price cap number or may be indexed to movement of an underlying cost. Similarly, ceiling tariffs may be calculated on the basis of normative costs as determined by the Appropriate Commission or may be based on paying capacity of consumers. These options of implementing Ceiling Tariffs have been identified and their pros/ cons have been evaluated in this chapter of the report.

5.1.3. Various options on different aspects of cost or tariff structuring, are summarized in the following figure:

Figure 9: Options for ceiling tariffs



5.1.4. The Pros and Cons of each of the options are as follows:

Table 4: Options for defining ceiling tariffs

Aspect	Option	Description	Pros	Cons
Mode	**Price Cap**	A maximum tariff rate on per unit basis, below which retailers/ suppliers can set their own tariffs	• Easy to comprehend for consumers and other stakeholders	• Would have to set at a level higher than actual tariffs, to allow for innovation in tariff schedules • Would require detailed exercise for ceiling tariff determination

Aspect	Option	Description	Pros	Cons
	Indexed	Tariffs determined by the Commission in tariff order, linked to movement in index such as inflation or wholesale market price	• Can be auto calculated by utilities; minimal regulatory intervention required	• May lead to high fluctuations in tariffs; difficult for consumers to comprehend/ track
	Default Tariff	A basic/ common tariff schedule, required to be offered by all suppliers/ DISCOMs	• Can protect consumers from cases where suppliers cartelize and only offer higher or a particular type of tariff schedule	• More relevant once retail competition is implemented • Not absolute ceiling; retailers may technically still offer higher tariffs, but they may not have economic rationale for consumers • May lead to be significantly higher tariffs than actual costs • Would require detailed process for tariff determination including stakeholder consultations
Layer/ Level	**Average Billing Rate (ABR)**	Setting a maximum Average Billing Rate, on per unit basis, that can be charged to consumers	• Easier to comprehend and compare for consumers, especially where a complex tariff structure exists with large number sub-categories	• Actual ABR for each consumer differs based on their consumption profile
	Average Cost of Supply (ACS)	Setting maximum cost of supply on per unit basis that can be incurred by utility	• Easier to calculate; will not depend on consumers mix; can be determined voltage wise • Clear indicator for utilities to control costs	• Not directly comparable with consumer tariffs • Does not account for cross subsidy in tariffs
	Tariff Rate	Setting a maximum tariff rate that can be charged to each consumer type	• Easy to comprehend and compare against actual tariffs by consumers	• Requires detailed assumptions for consumer categories/ sub-categories • Difficult to implement in states with complex tariff structure
Formulation	**Normative**	Calculated using norms and actual historical costs, on cost plus basis	• Incentivizes performance improvement • Can be based on upper limits/ targets for controllable components such	• Need to create sufficient headroom or pass through impact of uncontrollable factors like varying customer base

Aspect	Option	Description	Pros	Cons
			as AT&C loss, O&M expense etc.	
	Average/ %tile	Calculated as a figure somewhere in between actual tariffs of all DISCOMs, either average of all or say 90th percentile	• Does not require an efficient utility norms to be defined	• Applicable only for states with multiple utilities (with different tariffs) • Assumes that price/ cost among varies utilities only because of efficiency and not because of customer base/ demographics • May lead to slower performance improvement
	Paying capacity	Calculated based on actual paying capacity of consumers	• Maintains affordable tariffs	• Not absolute ceiling; prudent costs of utility may be higher than paying capacity of consumers; May require Govt. support to fund gap
Applicability (on consumers)	**Single ceiling rate for all consumers**	Common ceiling tariff for all consumer types of a DISCOMs in a State	• Easy to comprehend and compare against actual tariffs by consumers	• Low control over impact on individual categories
	Consumer category wise	Separate ceiling tariff for each consumer category like domestic, agriculture etc. Or applied on select consumers based on parameters such as their consumption level, their location etc.	• Can take into consideration specifics of each consumer category • Takes into account existing level of cross subsidies; Select category can be protected from high tariffs	• Would need to be adjusted with changing consumer mix
	Range for consumer categories	A range of say ±20% may be defined within which DISCOM may charge consumers	• Provides flexibility to set tariffs	• May lead to inverted tariff structures
Applicability (region)	**State-Wide**	Single ceiling rate for all DISCOMs in a state	• Relevant for states like Punjab, Tamil Nadu etc. with single DISCOM or states like Bihar, Haryana etc. where uniform retail tariff is charged to consumers of all DISCOMs	NA
	Area wise	Ceiling determined individually for a particular area or DISCOM area in the State	SERCs may choose to calculate ceiling rates separately for a select area in following cases:	NA

Aspect	Option	Description	Pros	Cons
			1. Region with parallel licenses (like Mumbai in Maharashtra) 2. DISCOM with separate tariff than other DISCOMs in the State (like NPCL in Uttar Pradesh)	
Period	**Annual**	Defined at a fixed frequency, say annually	• Ease of calculation	• Short-term visibility to consumers
	Dynamic	In case of indexed tariffs, changed automatically	• Better pass through of variabilities	• Suitable for indexed tariffs • Requires frequent revisions to billing rates
	Control Period	Defined for a period of 3-5 years	• Long term visibility to consumers	• Difficult to account for unforeseen expenses

5.1.5. In line with the pros and cons of various options discussed above, the ceiling tariffs may be described as follows:

Ceiling Tariffs may be described as a ***maximum Average Billing Rate (ABR)*** *that may be charged to various* ***consumer categories*** *in the* ***State or a particular area****, during the* ***Control Period*** *as per tariff regulations, determined by the Appropriate Regulatory Commission using* ***normative or approved costs as per tariff regulations****.*

6. Methodology for calculation of Ceiling Tariffs

6.1. Overall methodology

6.1.1. SERCs may use this suggested methodology as broad principles for determination of ceiling tariffs, with suitable alterations based on their state specific considerations.

6.1.2. Subsequent sub-sections discuss in detail suggested methodology for each individual cost component forming part of ceiling tariffs.

6.2. Cost of Power

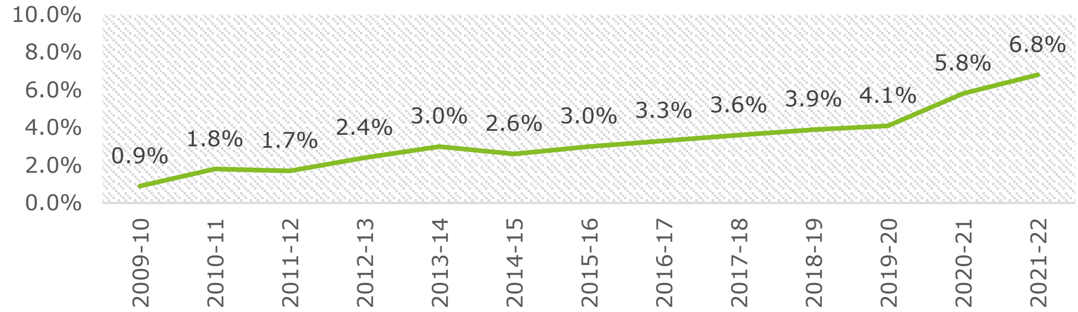
6.2.1. The cost of power for ceiling tariffs may be estimated using following approaches:

Table 5: Approaches for power purchase cost estimation in ceiling tariffs – Pros and Cons

Sl.	Option	Description	Pros	Cons
I.	**Basis actual PPAs/ sources of power of DISCOMs in the State**	Weighted average cost of power from various sources, based on prevalent PPA rates and source mix	• More closer to procurement practice currently followed by DISCOMs in India	• Low incentive for DISCOM to optimize its power procurement cost/ practices
II.	**Exchange based approach**	Based on historical average (6-12 months) of cost of power traded on wholesale market/ exchange, for an appropriate period	• Does not assume a power procurement strategy for utility; a utility operating efficiently can supply at this rate by simply procuring power from market	• Can lead to high fluctuations in costs • Requires a well-developed and deep market, for a benchmark price

6.2.2. In Indian context, the States have long-term PPAs from various generation sources including central generating stations, state generating stations, IPPs, etc. Also, the depth of power exchanges in India is observed to be very low and is used primarily for meeting short-term demand supply variations only. As per CERC's 'Report on Short-Term Power Market in India: 2021-22' while the share of short term power market traded through exchanges has increased gradually over the years, it still constituted just 6.8% of the total electricity generation in India in FY 2021-22. Therefore, complete reliance of exchange determined power purchase cost may not represent the cost of power procurement for the purpose of ceiling tariff.

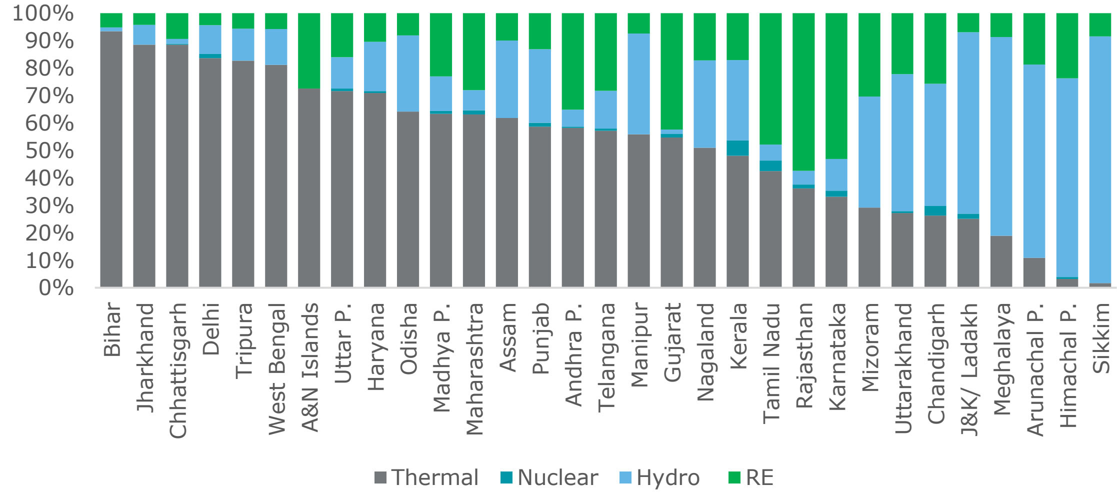
Figure 10: Volume of power traded on exchanges as % of Total Electricity Generation in India



Source: CERC Report on Short-Term Power Market in India: 2021-22

6.2.3. Further while thermal power forms the majority share of installed capacity of power in India, the power mix varies significantly from state to state.

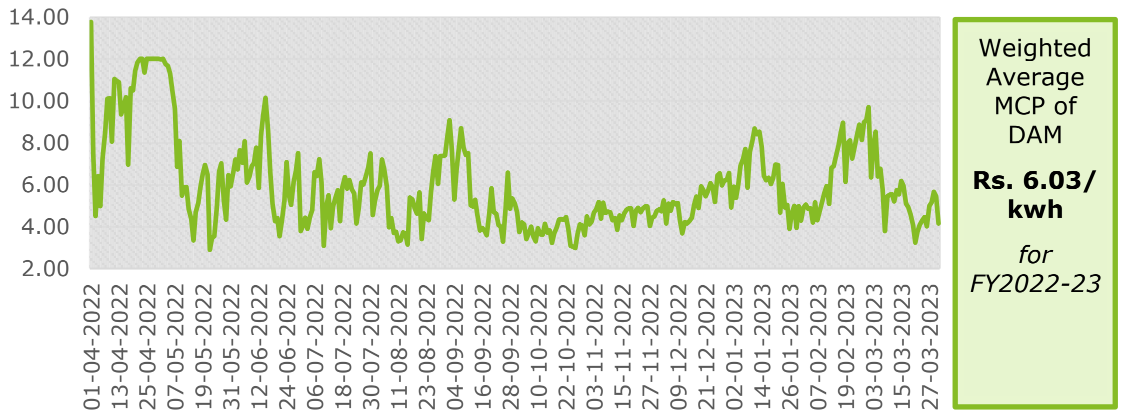
Figure 11: State-Wise mix of installed generation capacity (as on 31-Mar-2023)



Source: CEA report on all India installed capacity

6.2.4. DISCOMs generally buy power from short term markets through products like Day-Ahead-Market (DAM) or Real-Time-Markets (RTM) to meet their incremental needs such as during peak hours, during plant outages or when cheaper power is available on the markets. High variations are observed in Market Clearing Prices on power exchanges, especially when there is power shortage due to high peak demands or low fuel availability.

Figure 12: Daily Average Market Clearing Price on DAM (Rs./Kwh)

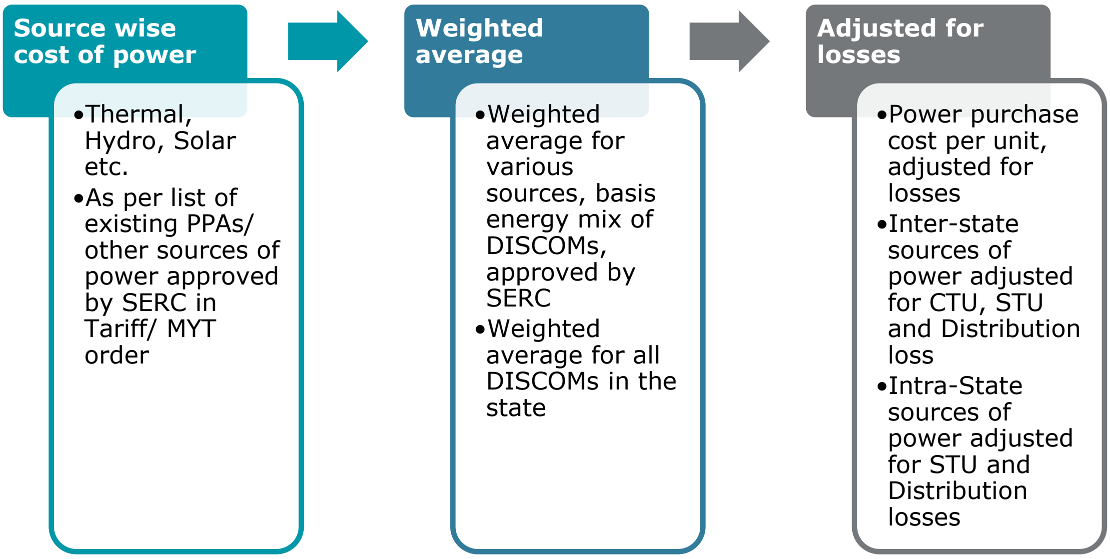


Source: IEX

6.2.5. In accordance with the context of current procurement practice followed by DISCOMs, till the time the short term power markets are not deep enough, the cost of power for ceiling tariffs may be determined as weighted average power purchase cost of all DISCOMs in the State, as approved by the SERC (based on existing PPAs of the DISCOM).

6.2.6. Further the power purchase cost may be adjusted for transmission and distribution losses. While the inter-state transmission losses may be taken as per actual CTU losses in the recent past, the intra-state transmission and distribution losses may be taken as per approved loss trajectory by SERC. Use of SERC approved loss trajectory shall induce efficiency improvement among DISCOMs.

Figure 13: Methodology for determining Cost of Power in Ceiling Tariffs



6.2.7. In addition to the cost of power determined basis PPAs, Fuel Price Purchase Adjustment Cost (FPPCA) if any approved by the SERC, may also be allowed in ceiling tariffs as per prevalent regulations in the state.

6.2.8. In case there aren't multiple DISCOMs to calculate weighted average cost, the Commission may take other suitable reference rates (for instance Power Exchange), in line with international experience , as per their prudence. The following table presents a market data analysis of movement in power purchase price on IEX in the recent years, that may be used for benchmarking by the SERCs.

Table 6: Price of electricity transaction in IEX

Month	**DAM, MCP** (Rs./kwh)			**G-DAM, MCP** (Rs./kwh)			**Overall Avg.** (illustrative)
	Min	Wtd Avg	Max	Min	Wtd Avg	Max	
	D_L	D	D_M	G_L	G	G_M	25*G+75*D
Average - CY2023							**5.49**
Dec-23	2.05	4.69	10.00	2.85	4.86	10.00	4.73
Nov-23	2.00	4.16	10.00	3.25	4.69	10.00	4.29
Oct-23	1.50	6.36	10.00	1.70	6.37	10.00	6.36
Sep-23	1.08	5.87	10.00	3.00	6.47	10.00	6.02
Aug-23	1.98	6.43	10.00	1.83	6.19	10.00	6.37
Jul-23	1.00	4.47	10.00	1.83	4.31	10.00	4.43
Jun-23	1.33	5.16	10.00	1.84	4.95	10.00	5.11
May-23	1.78	4.77	10.00	2.00	4.66	10.00	4.74
Apr-23	1.42	5.24	10.00	1.89	5.67	10.00	5.35
Mar-23	2.22	5.44	12.00	3.34	5.67	12.00	5.50

Month	DAM, MCP (Rs./kwh)			G-DAM, MCP (Rs./kwh)			Overall Avg. (illustrative)
	Min	Wtd Avg	Max	Min	Wtd Avg	Max	
	D_L	D	D_M	G_L	G	G_M	25*G+75*D
Feb-23	2.82	6.64	12.00	2.99	6.57	12.00	6.62
Jan-23	2.00	6.36	12.00	2.86	6.30	12.00	6.35
Average - CY2022							**5.79**
Dec-22	2.00	5.58	12.00	2.00	5.24	12.00	5.50
Nov-22	2.71	4.80	12.00	2.71	4.91	12.00	4.83
Oct-22	1.12	3.96	12.00	2.58	4.02	12.00	3.98
Sep-22	1.20	5.87	12.00	2.88	5.42	12.00	5.76
Aug-22	1.31	5.43	12.00	2.80	5.20	12.00	5.37
Jul-22	1.50	5.50	12.00	2.80	4.63	12.00	5.28
Jun-22	1.00	6.88	12.00	2.97	5.94	12.00	6.65
May-22	1.00	6.81	12.00	3.00	5.91	12.00	6.59
Apr-22	2.70	9.52	20.00	3.65	9.29	20.00	9.46
Mar-22	2.42	7.95	20.00	3.25	6.96	20.00	7.70
Feb-22	2.00	4.60	20.00	2.50	4.78	18.00	4.65
Jan-22	1.58	3.58	11.27	1.00	4.20	8.00	3.74

Source: CERC Market Monitoring Reports

6.3. Network Cost

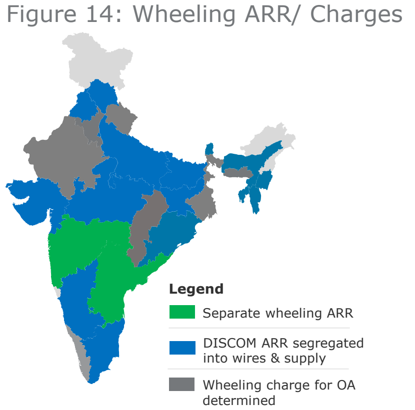
6.3.1. The network costs shall comprise of:

- Inter-State Transmission or CTU charges, as published by POSOCO
- Intra-State Transmission or STU charges, as approved by respective SERC
- Distribution Wheeling charges, as per approved Wheeling ARR by SERC

6.3.2. These charges can be considered on a per unit basis considering the approved amount and quantum of energy which is expected to flow in the system as determined by the SERC in its Tariff or MYT order for the respective DISCOM.

6.3.3. For wheeling charges of DISCOM, weighted average of all DISCOMs in the state (basis their energy sales) may be considered. In case there are parallel licensees in any DISCOM's area, and the Commission determines wheeling charges (or ARR) for these parallel licenses as well, then in such case the wheeling charges of the DISCOM with the most expansive network (i.e. with largest network coverage) may be considered for calculation of ceiling tariffs.

Figure 14: Wheeling ARR/ Charges



6.3.4. Few SERCs - like in the states of Maharashtra, Andhra Pradesh and Telangana – determine separate ARR for wheeling business of DISCOMs. Many others – like Bihar, Gujarat, Uttar Pradesh etc. – segregate the DISCOM's overall ARR into wires and supply businesses using certain assumption/ norms. For these two type of states, the wheeling charges of DISCOM for ceiling tariffs may be taken as wires business ARR divided by the total energy wheeled or sold.

6.3.5. In states (like Haryana[10]) where neither separate ARR is determined for wheeling business of DISCOM, nor overall ARR is segregated into wires and supply

[10] Due to lack of DISCOM accounts segregated into wires and supply business, in its Tariff Order for FY2023-24, the Haryana Electricity Regulatory Commission (HERC) has considered a fixed 9.56% of DISCOM's total ARR as wheeling expense and divided it by voltage wise energy sales to calculate wheeling charge for Open Access; In this approach, even an increase in power purchase cost, may lead to an increase in wheeling expenses; this is unlike the approach followed by some of the other SERCs, which segregate component wise ARR costs into wires and supply businesses

business, the wheeling charges determined for Open Access may be used as substitute for determination of ceiling tariffs.

Table 7: Methodology for determining Network Costs in ceiling tariffs

Sl.	Network Cost	Methodology
a.	**Inter-State Transmission**	• Approved cost basis rates published by POSOCO and approved by SERC in MYT or Tariff order, divided by total energy sales
b.	**Intra-State Transmission**	• Approved cost (in MYT or Tariff order) by SERC, divided by total energy sales
c.	**Distribution wheeling**	• For DISCOMs with separate wheeling ARR: wheeling charge determined by SERC on per unit basis • For DISCOMs with ARR segregated into wires & supply: wires ARR, approved by SERC (in MYT or Tariff order), divided by total energy sales • For DISCOMs where ARR is not segregated: wheeling charge on per unit basis as determined for Open Access sales

6.4. Operating Cost (Supply)

6.4.1. Operating cost refers to cost incurred to acquire and serve consumers including activities such as metering, billing/ collection, customer service etc. This cost may be determined by adopting following methodology:

- **Segregated ARR for supply business of DISCOM is available:** as discussed in the sub-section of Network Costs, in DISCOMs where separate or segregated ARR for wires and supply business is available, the Operating Cost may be taken as supply business ARR (disregarding non-tariff income i.e. not reducing it from ARR) of the DISCOM divided by its energy sales. SERCs typically allocate a portion of ARR expense items such as O&M expense, Depreciation, Interest on Loans, Interest on Working Capital and ROE to Supply business – O&M expense forming the majority portion.

- **Segregated ARR for supply business of DISCOM, NOT available:** In cases where separate or segregated ARR for supply business of DISCOM is not available, the Operating Cost may be calculated as DISCOM's total ARR, less power purchase cost, less wheeling expenses (wheeling charge for Open Access multiplied by energy sales) divided by energy sales.

$$\frac{\left(\begin{array}{l}\text{Total DISCOM ARR}\\ \quad\text{Less: Cost of Power}\\ \quad\text{Less: Transmission Expense}\\ \quad\text{Less: Wheeling charge for Open}\\ \quad\text{Access multiplied by energy sales}\end{array}\right)}{\text{Energy Sales}}$$

6.4.2. For the Operating Cost, weighted average of all DISCOMs (basis their energy sales) in the state/ region may be considered. In case there are parallel licensees in any DISCOM's area, the Commission may consider to include their operating cost in weighted average as well, but may exclude any smaller utility with very high per unit operating cost due to smaller consumer base.

6.5. Headroom margin

6.5.1. Taking cue from international experience of United Kingdom (UK), in addition to the prudent costs as determined by the Regulator (in its MYT or Tariff Order), an additional buffer may be allowed in the Operating Cost (supply). The margin may be allowed over and above the Operating Cost (Supply).

6.5.2. It is envisaged that the Regulator may calculate Operating Cost (Supply) for Ceiling Tariffs only once at the beginning of a Control Period (but separately for each year of the Control Period) or once every few years, without any true-up for cost escalations. Hence a headroom may be allowed for such unforeseen costs in the Operating Cost (Supply) portion of the ceiling tariffs.

6.5.3. This Headroom shall also act as a margin for competition among multiple DISCOMs/ suppliers. DISCOMs may improve their operational efficiency and keep operating cost (supply) below ceiling, to enjoy higher returns.

6.5.4. The Regulator may take a prudent call on the level of headroom to be allowed in Ceiling Tariffs, based on variation between MYT approved costs and Trued-up or Actual Costs, in recent years basis factors such as:

Table 8: Factors for headroom in Ceiling Tariffs

Sl.	Factor	Description	Methodology	
			Variation (%)	**Weight (%)**
1.	**O&M expenses**	High gap between actual and approved figures can lead to accumulated losses of DISCOMs	• % change between Actual (True-up filling/ Accounts/ True-up approved) and MYT approved O&M Expenses • Averaged for a period of say last 3 true-ups done by Regulator	• Share of O&M expense in ARR (excl. power purchase cost), multiplied by share of operating cost (supply) in ceiling tariff
2.	**Additional Capital Expenditure**	Tariffs in MYT or Tariff orders are based on capex projections generally done as part of DISCOM's Business Plan. However during true-up, the Commission may allow additional capitalization for projects/ schemes which are prudent and necessary. A margin may be built to allow for such additional capex, in supply side business of DISCOM.	• A margin of say 5% to 10% of Capex amount, basis prudence of the Commission • To convert the additional capex into annualized expense, this 5-10% margin shall than be multiplied by: i. Depreciation Rate ii. Debt Ratio (70%), multiplied by Rate of Interest iii. Equity Ratio (30%) multiplied by Rate of ROE • Sum of all these three figures may be used as variation %.	• Share of Depreciation plus interest on loan plus ROE in ARR (excluding power purchase cost), multiplied by share of operating cost (supply) in ceiling tariff
3.	**Bad Debt Provisioning**	Several SERCs in their tariff regulations allow for provision for bad and doubtful debts ***Note:*** *Allowance for Bad Debt shall not be required,*	• The sub-total of Cost of Power, Network Cost and Operating Cost may be marked-up with an allowance of say 1% to 2%	• Not applicable

Sl.	Factor	Description	Methodology	
			Variation (%)	**Weight (%)**
		if while calculating ARR for wires or supply business of DISCOM, the Commission has already considered a separate expense item for Bad Debt and that is getting passed through in Ceiling Tariffs		
4.	**Any other un-controllable cost[11], if any**	Any other prudent cost not covered above.	• % change between Trued-up and MYT/ Tariff approved figures • Averaged for a period of say last 3 true-ups done by Regulator	• Share of the uncontrollable cost expense in ARR (excluding power purchase cost), multiplied by share of operating cost (supply) in ceiling tariff

6.5.5. The provisions for bad debt provisioning in tariff regulations of various SERCs is as follows:

Table 9: Provisions for bad and doubtful debt in tariff regulations of select states

State	Provision
Uttar Pradesh	Regulation 46 of UPERC MYT Regulations, 2019: For any Year, the Commission may allow a provision for write off of bad and doubtful debts up to ***2% of the amount shown as Revenue Receivables*** from sale of electricity in the audited accounts of the Distribution Licensee
Punjab	Regulation 47 of PSERC MYT Regulations 2019: Bad and doubtful debts shall be allowed to the extent the Distribution Licensee has identified/actually written off bad debts, subject to a maximum of ***1% of annual sales*** revenue excluding subsidy
Maharashtra	Regulation 76 of the MERC MYT Regulations 2019: The Commission may allow a provision for writing off of bad and doubtful debts up to ***1.5% of the amount shown as Trade Receivables*** …… 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 during the year, subject to the above ceiling of 1.5%
Madhya Pradesh	Regulation 37 of MPERC (Terms and Conditions for Determination of Tariff for Supply and Wheeling of Electricity and Methods and Principles for Fixation of Charges) Regulations 2021: Bad and doubtful debts shall be allowed based on bad debts actually written off in the past ….. to the extent commission considers it appropriate and shall be trued up during the true-up exercise for the relevant year subject to a limit of ***1% of the yearly revenue***.
West Bengal	Section 5.10 of WBERC (Terms and Conditions of Tariff) Regulations, 2011: The Commission may allow such amount of bad debts as actually had been written off in the latest available audited accounts of the generating companies / licensees subject to a ceiling of ***0.5% of the annual gross sale value*** of power at the end of the current year.’
Andhra Pradesh	Fifth Amendment to The Andhra Pradesh Electricity Regulatory Commission (Terms And Conditions For Determination Of Tariff For Wheeling And Retail Sale Of Electricity) Regulation, 2005

[11] Excluding any uncontrollable cost already passed through in tariffs, using automatic adjustment mechanism like FPPPA/ FAC

State	Provision
	12.6 Provision for bad debts: Bad and doubtful debts in the ARR shall be allowed based on the actual written-off bad debts in the past 5 years as per the audited financial statements to the extent Commission considers them appropriate subject to a ceiling limit of **1% of the yearly revenue** at the discretion of the Commission
Assam	AERC (Terms and Conditions for determination of Multi Year Tariff) Regulations 2021, Chapter 9: Components of ARR and Tariff for Retail Supply Business, Section 92.8 Provision for Bad and doubtful debts: The Commission may allow a provision for bad and doubtful debts upto ***1% of the amount shown as receivables*** in the audited accounts of the Distribution Licensee, duly allocated for the supply business.

6.6. Impact of ceiling tariffs on Consumers

6.6.1. The overall Ceiling Tariff determined as sum of 'Cost of Power', 'Network Cost', 'Operating Cost' and 'Margins', may be converted into a range for consumer category wise ABR of say ±20% as per Tariff Policy 2016. Utilities may charge consumers within this range of ABR.

6.6.2. While tariffs of individual sub-categories/ slabs may go beyond the range of ceiling tariffs defined for these broad categories, DISCOMs may be required to meet the ceiling on an overall level.

6.7. Impact of ceiling tariffs on DISCOMs

Efficiency Margins

6.7.1. The headroom in ceiling tariffs, shall act as an efficiency margins for DISCOMs to compete with other utilities. DISCOMs may improve their operational efficiency and keep operating cost (supply) below ceiling, to enjoy higher returns.

6.7.2. Utilities with actual operating cost (supply) lower than the ceiling, may enjoy an increased profit/ return margin, in case tariffs are set above its actual cost but below ceiling level. To prevent any undue profits to such DISCOM(s), the SERCs may incorporate such efficiency of DISCOM(s) in ceiling tariff calculations in the subsequent rate cycles i.e. in the next rate cycle, the ceiling tariff level may be brought down considering lower actual operating cost (supply) of the DISCOM(s) for calculations.

6.7.3. On the other hand to prevent any significant under-recovery or loss to licensees, the SERC may allow for adequate pass-through of any uncontrollable costs (for items not already built in headroom margin) during the true-up.

Allocation of Distribution Loss

6.7.4. Post segregation of supply and network business for ceiling tariffs, the impact of higher/ lower than approved distribution losses, shall also have to be either segregated or allocated between supply and network businesses.

6.7.5. Currently, the impact of higher than SERC approved distribution losses is borne by DISCOM as a whole, which accumulates as losses. Going forward, once supply and network business is segregated and only ceiling is determined for the supply business, the impact of distribution losses would also have to be segregated between network and supply business, basis causality and prevalent level of losses.

6.7.6. FOR's report on 'Roll out Plan for Introduction of Competition in Retail Sale of Electricity' suggests various approaches for allocating the distribution losses between network and supply business. The report suggests allocating technical losses to the network business and collection efficiency portion of the commercial losses to the supply business. The remaining portion of the commercial losses (due to factors like theft or inaccurate metering etc.) may be allocated to either network or supply business, based on the boundary of segregation between the two businesses (i.e. who has responsibility of consumer metering) and prevalent level of losses (i.e. maybe with network business if loss levels are low, otherwise with supply business).

6.7.7. For the portion of losses allocated to network company, the network company may have to compensate supply business for the additional cost of power due to higher than approved loss trajectory. Alternatively, if actual loss is lower than approved trajectory, then the supply company may compensate network company for the same.

7. Illustrative calculations for Ceiling Tariffs

7.1. Headroom allowance

7.1.1. In order to suggest a suitable level of headroom for operating costs in ceiling tariffs, illustrative calculations are done for select states. State of Bihar, Maharashtra, Haryana and Tamil Nadu are selected for the analysis. These states represent various regions of India and also cover various tariff determination methodologies followed by SERCs.

7.1.2. Headroom margins are analysed on the basis of cost variations between MYT/ Tariff Order approved figures and True-up Filed/ True-up approved figures for last three trued-up years of FY2019-20 to FY2021-22.

Table 10: Maharashtra: Cost variation-MYT/ Tariff Order approved figures and True-up Filed/ True-up approved figures

Maharashtra		Operating Cost (supply)			Variation	
Year	**Units**	**MYT**	**Actual**	**Trued-up**	**MYT vs Actual**	**MYT vs Trued-up**
FY20	Rs./kwh	0.83	0.84	0.69	0.01	-0.14
FY21	Rs./kwh	0.50	0.69	0.40	0.18	-0.11
FY22	Rs./kwh	0.63	0.68	0.46	0.05	-0.17
Max variation					**0.18**	**-0.11**

Table 11: Bihar: Cost variation-MYT/ Tariff Order approved figures and True-up Filed/ True-up approved figures

Bihar		Operating Cost (supply)			Variation	
Year	**Units**	**MYT**	**Actual**	**Trued-up**	**MYT vs Actual**	**MYT vs Trued-up**
FY20	Rs./kwh	0.32	0.38	0.35	0.06	0.03
FY21	Rs./kwh	0.34	0.36	0.35	0.01	0.01
FY22	Rs./kwh	0.35	0.364	0.36	0.01	0.01
Max variation					**0.06**	**0.03**

Table 12: Haryana: Cost variation-MYT/ Tariff Order approved figures and True-up Filed/ True-up approved figures

Haryana		Operating Cost (supply)			Variation	
Year	**Units**	**MYT**	**Actual**	**True-up**	**MYT vs Actual**	**MYT vs Trued-up**
FY20	Rs./kwh	0.46	0.51	0.35	0.05	-0.10
FY21	Rs./kwh	0.43	0.53	0.36	0.10	-0.07
FY22	Rs./kwh	0.51	0.52	0.50	0.01	-0.01
Max variation					**0.10**	**-0.01**

Table 13:Tamil Nadu - Cost variation-MYT/ Tariff Order approved figures and True-up Filed/ True-up approved figures

Tamil Nadu		Operating Cost (supply)			Variation	
Year	**Units**	**MYT**	**Actual**	**True-up**	**MYT vs Actual**	**MYT vs Trued-up**
FY20	Rs./kwh	NA	0.49	0.47	NA	-0.02
FY21	Rs./kwh	NA	0.55	0.52	NA	-0.02
FY22	Rs./kwh	NA	0.50	0.44	NA	-0.06
Max variation					**NA**	**-0.02**

Note: In the case of Tamil Nadu there was no issuance of a Multi-Year Tariff (MYT) for the period from 2019-20 to FY 2021-22.

7.1.3. On an average, a variation of ~11 paisa per unit is observed in operating cost (supply) between MYT vs Actual figures in select states. Accordingly, headroom of 10 paisa per unit may considered in illustrative ceiling tariffs.

7.2. Maharashtra – Ceiling Tariff

7.2.1. In the Mumbai region of the Maharashtra state, four distribution licensees i.e. BEST, Adani Electricity Mumbai Limited (formerly RInfra-D or BSES), MSEDCL (limited to few suburbs) and Tata Power Company (TPC-D) hold the licence to distribute electricity within the areas specified in their respective licences.

7.2.2. MERC determines tariffs separately for AEML (formerly RInfra-D or BSES), TPC-D, BEST and MSEDCL through separate tariff orders. Each of these tariff order, adheres to same principles/ methodology set under the MERC's MYT Regulations. Unlike other states with multiple DISCOMs like Madhya Pradesh, Rajasthan etc., tariff of each utility in Maharashtra is different on account of different cost levels of the utilities, and there is no uniform tariff across the State.

7.2.3. The MYT Order for these utilities were issued in Mar-2020 for control period of FY 2020-21 to FY 2024-25. Thereafter the Commission has issued tariff orders for FY 2023-24 and FY 2024-25, wherein costs and tariffs were revised basis more recent estimates. Considering that significant differences have occurred in the costs approved under MYT Order, the latest tariff order for FY 2023-24 an FY 2024-25 has been considered for calculation of illustrative Ceiling Tariffs.

7.2.4. In line with methodology discussed previously in this report, the calculations of ceiling tariffs for the State of Maharashtra are detailed in subsequent paras.

Cost of Power

7.2.5. Approved power purchase cost and approved power purchase units of all DISCOMs – MSEDCL, AEML, TPC-D and BEST are assessed to calculate weighted average Power Purchase Rate for the state. These are then adjusted for approved transmission and distribution losses by the Commission. The adjustment for losses is done by dividing the combined total power purchase cost of all DISCOMs, by combined approved energy sales of all DISCOMs.

7.2.6. Accordingly, for the calculation of illustrative ceiling tariffs for the State of Maharashtra, the overall approved Weighted Average Power Purchase Cost is considered, as follows:

Table 14: Maharashtra: Illustrative Ceiling Tariff – Cost of Power (FY 2023-24)

FY 2023-24	**MSEDCL**		**TPC-D**		**AEML**		**BEST**		**Overall** (Wtd. Avg.)	
Particulars	Mix	Rate	Mix	Rate	Mix	Rate	Mix	Rate	Mix	Rate
Source Type	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*
Thermal	75%	4.93	58%	7.38	28%	5.38	63%	7.10	71%	5.07
Hydro	4%	2.32	0%	0.00	15%	3.24	15%	4.35	5%	2.72
Solar	10%	3.44	17%	3.06	46%	4.45	9%	5.15	13%	3.71
Non-Solar	11%	5.03	18%	4.50	5%	5.00	10%	4.90	11%	5.00
ST	0%	0.00	6%	5.13	6%	5.13	4%	7.43	1%	5.48
Total, Ex-Bus		**4.70**		**5.97**		**4.60**		**6.32**		**4.79**

FY 2023-24 Particulars	MSEDCL		TPC-D		AEML		BEST		Overall (Wtd. Avg.)	
	Mix	Rate	Mix	Rate	Mix	Rate	Mix	Rate	Mix	Rate
T&D Losses										
CTU Loss		3.55%		3.55%		3.55%		3.55%		3.55%
STU Loss		3.18%		3.18%		3.18%		3.18%		3.18%
Distribution Loss		13.00%		1.02%		6.80%		4.18%		7.93%
PPC Cost (Rs. Cr.)		68,800		3,451		5,376		3,252		80,879
Energy Sales (MUs)[12]		123,955		5,564		10,986		4,787		145,291
PPC at Consumer Level (Rs./Kwh)		**5.55**		**6.20**		**4.89**		**6.79**		**5.57**

Table 15: Maharashtra: Illustrative Ceiling Tariff – Cost of Power (FY 2024-25)

FY 2024-25 Particulars	MSEDCL		TPC-D		AEML		BEST		Overall (Wtd. Avg.)	
	Mix	Rate	Mix	Rate	Mix	Rate	Mix	Rate	Mix	Rate
Source Type	%	*Rs./ Kwh*	%	*Rs./ Kwh*	%	*Rs./ Kwh*	%	*Rs./ Kwh*	%	*Rs./ Kwh*
Thermal	73%	5.01	63%	5.11	34%	5.11	59%	7.24	69%	5.07
Hydro	3%	2.35	0%	0.00	14%	3.24	0%	0.00	4%	2.57
Solar	13%	3.38	16%	3.06	45%	4.40	25%	4.42	16%	3.63
Non-Solar	11%	4.96	0%	0.00	0%	0.00	10%	4.69	10%	5.05
ST	0%	0.00	21%	5.13	8%	5.13	6%	5.13	1%	5.13
Total, Ex-Bus		**4.70**		**4.99**		**4.57**		**6.15**		**4.75**
T&D Losses										
CTU Loss		3.55%		3.55%		3.55%		3.55%		3.55%
STU Loss		3.18%		3.18%		3.18%		3.18%		3.18%
Distribution Loss		12.00%		1.02%		6.55%		4.18%		6.90%
PPC Cost (Rs. Cr.)		69,592		3,618		5,520		3,339		82,068
Energy Sales (MUs)[13]		126,805		5,824		11,819		5,038		149,487
PPC at Consumer Level (Rs./Kwh)		**5.49**		**6.21**		**4.67**		**6.63**		**5.49**

Network Cost

7.2.7. Transmission charges:

- Transmission charges approved by the Commission for FY 2023-24 and FY 2024-25 (as per Tariff Order) are used for calculation of illustrative ceiling tariffs. Weighted average charge for all DISCOMs is considered
- Approved Inter-state transmission (CTU) charges for MSEDCL are considered for calculation of illustrative ceiling tariffs, as this cost of per unit basis shall be similar for all DISCOMs in the state
- For Intra-state transmission (STU) charges, sum of approved costs of all DISCOMs in the state is considered, as the total STU cost is allocated among DISCOMs in the state.
- These costs are divided by per unit approved energy sales, to calculate per unit charge.

[12] *Energy sales of TPC-D is considered as its own direct sales plus changeover sales from AEML, as TPC-D incurs power purchase cost for both such sales*
[13] *Energy sales of TPC-D is considered as its own direct sales plus changeover sales from AEML, as TPC-D incurs power purchase cost for both such sales*

Table 16: Maharashtra – Illustrative Ceiling Tariff – Transmission Network Cost (FY 2023-24)

Particulars	Units	MSEDCL	TPC-D	AEML	BEST	Overall *(Wtd. Avg.)*
Inter-State Transmission						
CTU expense	Rs. Cr.	3,845	NA	NA	NA	3,845
Energy Sales	MUs	123,955	NA	NA	NA	3,845
CTU Charge	Rs./Kwh					0.31
Intra-State Transmission						
STU expense	Rs. Cr.	8,594	278	492	233	9,597
Energy Sales[14]	MUs	123,955	3,994	12,455	4,787	145,190
STU Charge	**Rs./Kwh**					0.66
Transmission Charge	**Rs./Kwh**					**0.97**

Table 17: Maharashtra - Illustrative Ceiling Tariff - Transmission Network Cost (FY 2024-25)

Particulars	Units	MSEDCL	TPC-D	AEML	BEST	Overall *(Wtd. Avg.)*
Inter-State Transmission						
CTU expense	Rs. Cr.	4,037	NA	NA	NA	4,037
Energy Sales	MUs	126,805	NA	NA	NA	4,037
CTU Charge	Rs./Kwh					0.32
Intra-State Transmission						
STU expense	Rs. Cr.	8,639	331	590	300	9,860
Energy Sales	MUs	126,805	4,247	13,295	5,038	149,385
STU Charge	Rs./Kwh					0.66
Transmission Charge	**Rs./Kwh**					**0.98**

7.2.8. MERC in its tariff orders for DISCOMs, calculates ARR for Wires and Supply businesses separately, based on separate cost projections for various ARR components. The Commission determines three part tariffs for each utility – Fixed monthly charges, per unit energy charges and per unit wheeling charges. The per unit wheeling charges are determined based on wheeling ARR of the utility. Accordingly, wheeling charge determined by the Commission, for the DISCOM with most expansive network in the state i.e. MSEDCL, is considered for distribution wheeling charge in illustrative Ceiling Tariffs.

Table 18: Maharashtra - Illustrative Ceiling Tariff - Distribution Wheeling Charge (FY 2023-24)

Particulars	Units	MSEDCL	TPC-D	AEML	BEST	Overall (MSEDCL)
Distribution Wheeling Charge						
• HT	Rs./Kwh	0.60	0.99	1.00	0.68	0.60
• LT	Rs./Kwh	1.17	1.68	2.21	1.74	1.17

Table 19: Maharashtra - Illustrative Ceiling Tariff - Distribution Wheeling Charge (FY 2024-25)

Particulars	Units	MSEDCL	TPC-D	AEML	BEST	Overall (MSEDCL)
Distribution Wheeling Charge						
• HT	Rs./Kwh	0.60	1.22	1.17	0.77	0.60
• LT	Rs./Kwh	1.17	2.03	2.60	1.97	1.17

[14] *Energy sales of AEML is considered as its own direct sales plus changeover sales to TPC-D, as AEML incurs network cost for both such sales*

7.2.9. The overall network cost for illustrative Ceiling Tariffs for Maharashtra is as follows:

Table 20: Maharashtra - Illustrative Ceiling Tariff - Network Cost

Particulars	Units	FY24	FY25
Transmission Network Charge	Rs./Kwh	0.97	0.98
Distribution Wheeling Charge	Rs./Kwh	1.17	1.17
Total Network Charge	**Rs./Kwh**	**2.14**	**2.15**

Operating Cost (Supply)

7.2.10. Similar to the calculation for ARR of Wires Business, the Commission also calculates Supply Business ARR of each DISCOM in the state. Using this supply business ARR, the weighted average Operating Cost (Supply) is calculated for illustrative Ceiling Tariffs in Maharashtra, as follows:

Table 21: Maharashtra - Illustrative Ceiling Tariff - Operating Cost

FY 2023-24	Units	MSEDCL	TPC-D	AEML	BEST	Overall *(Wtd. Avg.)*
Supply Business ARR	Rs. Cr.	92,445	4,046	6,677	3,755	106,923
Less: Power Purchase Cost	Rs. Cr.	72,645	3,451	5,560	3,207	84,863
Less: Inter and Intra-state Transmission charges	Rs Cr.	8,593	278	492	233	9,596
Sub-Total	**Rs. Cr.**	**11,264**	**317**	**625**	**315**	12,521
Energy Sales[15]	MUs	123,955	3,994	12,455	4,787	145,190
Operating Cost (Supply)	**Rs./Kwh**	**0.91**	**0.79**	**0.50**	**0.66**	**0.86**

FY 2024-25	Units	MSEDCL	TPC-D	AEML	BEST	Overall *(Wtd. Avg.)*
Supply Business ARR	Rs. Cr.	95,199	4,253	7,311	4,059	110,822
Less: Power Purchase Cost	Rs. Cr.	73,629	3,616	6,059	3,433	86,737
Less: Inter and Intra-state Transmission charges	Rs Cr.	8639	331	590.48	300	9,860
Sub-Total	**Rs. Cr.**	**12,931**	**306**	**662**	**326**	**14,225**
Energy Sales	MUs	126,805	4246.91	13,295	5,038	149,385
Operating Cost (Supply)	**Rs./Kwh**	**1.02**	**0.72**	**0.50**	**0.65**	**0.95**

Headroom Margin

7.2.11. As discussed previously in the report, a fixed headroom of 10 paise/ unit may be allowed in the Operating Cost (supply) portion of the ceiling tariffs.

7.2.12. The overall illustrative ceiling tariff for the state of Maharashtra, post margins is as follows:

Table 22: Maharashtra - Illustrative Ceiling Tariffs

Particulars	Units	Item	FY24	FY25
Cost of Power	Rs./Kwh	A	5.57	5.49
Network Cost	Rs./Kwh	B	2.14	2.15

[15] *Energy sales of TPC-D is considered as its own direct sales plus changeover sales from AEML, as TPC-D incurs operating cost for both such sales.*

Particulars	Units	Item	FY24	FY25
Operating Cost	Rs./Kwh	C	0.86	0.95
Headroom	Rs./Kwh	D	0.10	0.10
Less: NTI	Rs./Kwh	E	0.04	0.04
Ceiling Tariff	**Rs./Kwh**	**D=A+B+C+D-E**	**8.63**	**8.65**
120% of Ceiling			10.35	10.38
80% of Ceiling			6.90	6.92

Impact on DISCOM and Consumers

7.2.13. To assess the impact of ceiling tariff on DISCOMs, the illustrative ceiling tariffs calculated is compared against the approved ACoS of DISCOMs in the state, as follows:

Table 23: Maharashtra: Illustrative ceiling tariffs - Impact on DISCOMs

Particulars	Units	FY24	FY25
Ceiling Tariff	Rs./Kwh	8.63	8.65
ACOS			
MSEDCL	Rs./Kwh	8.09	8.14
AEML	Rs./Kwh	8.57	8.76
TPC-D	Rs./Kwh	8.42	9.45
BEST	Rs./Kwh	9.48	9.15

7.2.14. To assess the impact of illustrative ceiling tariffs on consumers, the category wise Average Billing Rate (ABR) of DISCOMs is compared against the ±20% range of ceiling, as follows:

Table 24: Maharashtra: Illustrative ceiling tariffs - Impact on Consumers

Particulars	Units	FY24	FY25
Ceiling Tariff	Rs./Kwh	**8.63**	**8.65**
120% of Ceiling Tariff	Rs. Kwh	10.35	10.38
80% of Ceiling Tariff	Rs./Kwh	6.90	6.92
ABR, approved (wtd. avg.)			
MSEDCL			
Domestic (LT)	Rs./Kwh	8.90	9.47
Agricultural (LT)	Rs./Kwh	4.92	5.50
Commercial (LT)	Rs./Kwh	13.03	**13.51**
Industrial (HT)	Rs./Kwh	9.70	10.09
AEML			
Domestic (LT)	Rs./Kwh	7.82	7.98
Agricultural (LT)	Rs./Kwh	7.17	7.58
Commercial (LT)	Rs./Kwh	9.24	9.30
Industrial (HT)	Rs./Kwh	8.98	8.98
TPC-D			
Domestic (LT)	Rs./Kwh	6.79	8.19
Agricultural (LT)	Rs./Kwh	NA	NA
Commercial (LT)	Rs./Kwh	10.18	11.87

Particulars	Units	FY24	FY25
Industrial (HT)	Rs./Kwh	9.17	10.70
BEST			
Domestic (LT)	Rs./Kwh	7.76	8.29
Agricultural (LT)	Rs./Kwh	NA	NA
Commercial (LT)	Rs./Kwh	10.52	11.09
Industrial (HT)	Rs./Kwh	9.16	9.66

7.3. Bihar – Ceiling Tariff

7.3.1. There are two state owned DISCOMs in the state of Bihar – North Bihar Power Distribution Company Limited (NBPDCL) and South Bihar Power Distribution Company Limited (SBPDCL) – each operating exclusively in its licensed area.

7.3.2. Bihar Electricity Regulatory Commission (BERC) issued MYT Tariff order for these DISCOMS, for the control period FY 2022-23 to FY 2024-25 on 25-Mar-2022. In the MYT Order, while the Commission projects ARR for each year of the control period, tariff is determined only for the first year i.e. FY 2022-23. Post MYT Order, the Commission has also issued Tariff Order for FY 2023-24 on 23-Mar-2023, in which it revised the ARR for FY 2023-24.

7.3.3. Accordingly, illustrative ceiling tariff calculations for FY 2023-24 are done basis the latest available approved costs as per BERC's FY 2023-24 Tariff order.

7.3.4. In line with methodology discussed in previously in this report, the calculations of ceiling tariffs for the State of Bihar are detailed in subsequent paras.

Cost of Power

7.3.5. Approved power purchase cost and approved power purchase units of both the DISCOMs are added to calculate weighted average Power Purchase Rate for the state. These are then adjusted for approved transmission and distribution losses by the Commission.

7.3.6. While the BERC's MYT Tariff Regulations provide for pass through of monthly fuel and power purchase cost adjustment (FPPCA) charges, the Commission has not allowed for pass through of such costs in recent years. However the power purchase rate on per unit basis in Tariff Order of FY 2023-24 is higher than power purchase rate approved for FY 2023-24 in MYT Order, by ~13% overall.

Table 25: Bihar - Illustrative Ceiling Tariffs - Cost of Power

	FY 2023-24	
Particulars	**Energy Mix**	**Value**
Source Type	%	*Rs./Kwh*
Thermal	76%	5.57
Hydro	8%	2.97
RE	15%	3.04
ST	0%	0.00
Total, Ex-Bus		**4.97**
Inter-State Trans. Loss	%	3.34%
Intra-State Trans. Loss	%	3.00%
Distribution Loss	%	15.00%

Particulars	Energy Mix	FY 2023-24 Value
Total Power Purchase Cost (A)	Rs. Cr.	19,400
Total Energy Sales (B)	MUs	30,948
PPC at Consumer Level (A*10/B)	**Rs./Kwh**	**6.27**

Network Cost

7.3.7. Transmission charges approved by the Commission for FY 2023-24 (as per Tariff Order) are used for calculation of illustrative ceiling tariffs of Bihar. These costs are divided by per unit approved energy sales, to calculate per unit charge.

Table 26: Bihar - Illustrative Ceiling Tariff - Transmission Network Cost

Particulars	Units	Item	FY24
Inter-State Transmission Charge	Rs. Cr.	A1	1,935
Intra-State Transmission Charge	Rs. Cr.	A2	1,409
Total	**Rs. Cr.**	**A=A1+A2**	**3,344**
Energy Sales	MUs	B	30,948
Transmission Charge	**Rs./Kwh**	**A*10/B**	**1.08**

7.3.8. For distribution wheeling charge, total ARR of the two DISCOMs is segregated into wires and supply business ARR, using allocation norms as approved by the Commission. The wires business ARR is then divided by approved energy sales to calculate per unit distribution wheeling charge, as follows:

Table 27: Bihar - Illustrative Ceiling Tariff - Distribution Wheeling Charge

Particular	Allocation: Wires share	FY 2023-24 Total ARR	FY 2023-24 Wires ARR
O&M Expense		*Rs. Cr.*	*Rs. Cr.*
Employee cost	60%	1,192	715
R&M Expenses	90%	539	485
A&G Expenses	50%	374	187
Holding Co. expense	60%	52	31
Depreciation	90%	727	654
Interest on loans	90%	991	892
Other finance charges	10%	128	13
Return on Equity	90%	792	712
Interest on SD	0%	64	0
Interest on WC	10%	0	0
Total (A)		**Rs. Cr.**	**3,689**
Energy Sales (B)		MUs	30,948
Distribution Wheeling Charge (A*10/B)		**Rs./Kwh**	**1.19**

7.3.9. The overall network cost for illustrative Ceiling Tariffs for Bihar is as follows:

Table 28: Bihar: Illustrative Ceiling Tariffs – Network Cost

Particulars	Units	FY24
Transmission Network Charge	Rs./Kwh	1.08

Particulars	Units	FY24
Distribution Wheeling Charge	Rs./Kwh	1.19
Total Network Charge	**Rs./Kwh**	**2.27**

Operating Cost (Supply)

7.3.10. Similar to the calculation for Network Cost, the Operating Cost for supply side of the business is calculated as per allocation norms as approved by the Commission for supply business, as follows:

Table 29: Bihar - Illustrative Ceiling Tariff - Operating Cost (Supply)

Particular	Allocation: Supply share	FY 2023-24	
		Total ARR	Supply ARR
O&M Expense		*Rs. Cr.*	*Rs. Cr.*
Employee cost	40%	1,192	477
R&M Expenses	10%	539	54
A&G Expenses	50%	374	187
Holding Co. expense	40%	52	21
Depreciation	10%	727	73
Interest on loans	10%	991	99
Other finance charges	90%	128	115
Return on Equity	10%	792	79
Interest on SD	100%	64	64
Interest on WC	90%	0	0
Total (A)		Rs. Cr.	**1,169**
Energy Sales (B)		MUs	30,948
Operating Cost (Supply), A*10/B		**Rs./Kwh**	**0.38**

Headroom Margin

7.3.11. As discussed previously in the report, a fixed headroom of 10 paise/ unit may be allowed in the Operating Cost (supply) portion of the ceiling tariffs.

7.3.12. The overall illustrative ceiling tariff for the state of Bihar, post headroom margin is as follows:

Table 30: Bihar - Illustrative Ceiling Tariffs

Particulars	Units	Item	FY24
Cost of Power	Rs./Kwh	A	6.27
Network Cost	Rs./Kwh	B	2.27
Operating Cost	Rs./Kwh	C	0.38
Headroom	Rs./Kwh	D	0.10
Less: NTI	Rs./Kwh	E	0.62
Ceiling Tariff	**Rs./Kwh**	**D=A+B+C+D-E**	**8.40**
120% of Ceiling			10.08
80% of Ceiling			6.72

Impact on DISCOM and Consumers

7.3.13. To assess the impact of ceiling tariff on DISCOM, the illustrative ceiling tariffs calculated is compared against the approved ACoS of DISCOMs as follows:

Table 31: Bihar: Illustrative ceiling tariffs - Impact on DISCOMs

Particulars	Units	FY24
Ceiling Tariff	Rs./Kwh	8.40
ACOS		
NBPDCL	Rs./Kwh	8.21
SBPDCL	Rs./Kwh	8.37
Overall	Rs./Kwh	8.30

7.3.14. To assess the impact of illustrative ceiling tariffs on consumers, the category wise Average Billing Rate (ABR) of DISCOMs is compared against the ±20% range of ceiling, as follows:

Table 32: Bihar: Illustrative ceiling tariffs - Impact on Consumers

Particulars	Units	FY24
Ceiling Tariff	Rs./Kwh	**8.40**
120% of Ceiling Tariff	Rs. Kwh	10.08
80% of Ceiling Tariff	Rs. Kwh	6.72
ABR, approved (wtd. avg. of sub-categories)		
Domestic	Rs./Kwh	8.59
Agricultural	Rs./Kwh	10.28
Commercial	Rs./Kwh	11.29
Industrial	Rs./Kwh	**12.50**

7.4. Haryana – Ceiling Tariff

7.4.1. There are two state owned DISCOMs in the state of Haryana – Uttar Haryana Bijli Vitran Nigam (UHBVN) and Dakshin Haryana Bijli Vitran Nigam (DHBVN) – each operating exclusively in its licensed area.

7.4.2. Haryana Electricity Regulatory Commission (HERC) issued MYT Tariff order for these DISCOMS, for the control period FY 2020-21 to FY 2024-25 on 01-Jun-2020. In the MYT Order, while the Commission projected ARR for each year of the control period, detailed calculations of power purchase cost and its underlying assumptions were provided only for the first year i.e. FY 2020-21. O&M expenses were projected for control period basis norms as per regulations. Asset related costs of depreciation, interest and ROE, were projected basis capex approved year-on-year in business plan.

7.4.3. Post MYT Order, the Commission issued Tariff Order annually for each tariff year. The tariff Order for FY 2023-24 was issued 15-Feb-2023.

7.4.4. Considering that costs approved in MYT Order have undergone three iterations of tariff orders since then for FY 2021-22, FY 2022-23 and FY 2023-24, the illustrative ceiling tariff calculations are done basis Tariff Order for FY 2023-24, as these are more reflective of latest available costs figures.

7.4.5. In line with methodology discussed in previously in this report, the calculations of ceiling tariffs for the State of Haryana are detailed in subsequent paras.

Cost of Power

7.4.6. In the state of Haryana, power is purchased by Haryana Power Purchase Cell (HPPC), on behalf of the two DISCOMs. The Commission calculates an Average Power Purchase Cost

(APPC) for the state based on approved list of PPAs and costs determined by the Commission for State Owned Generation utility – HPGCL. The total power purchase cost is allocated between the DISCOMs, which has resulted in an approximately equivalent Power Purchase Cost on per unit basis for both the DISCOMs.

7.4.7. Accordingly, for the calculation of illustrative ceiling tariffs for the State of Haryana, the overall approved Average Power Purchase Cost (APPC) is considered, as follows:

Table 33: Haryana: Illustrative Ceiling Tariff - Cost of Power

		FY 2023-24
Particulars	**Energy Mix**	**Value**
Source Type	*%*	*Rs./Kwh*
Thermal	72%	4.39
Hydro	10%	2.18
RE	9%	3.34
ST	9%	6.28
Total, Ex-Bus		**4.24**
Inter-State Trans. Loss	%	3.48%
Intra-State Trans. Loss	%	2.05%
Distribution Loss	%	12.00%
Total Power Purchase Cost (A)	Rs. Cr.	28,283
Total Energy Sales (B)	MUs	56,546
PPC at Consumer Level (A*10/B)	**Rs./Kwh**	**5.00**

Network Cost

7.4.8. Transmission charges approved by the Commission for FY 2023-24 (as per Tariff Order) are used for calculation of illustrative ceiling tariffs of Haryana. These costs are divided by per unit approved energy sales, to calculate per unit charge.

Table 34: Haryana: Illustrative Ceiling Tariff - Transmission Network Cost

Particulars	Units	Item	FY24
Inter-State Transmission Charge	Rs. Cr.	A1	2,403
Intra-State Transmission Charge	Rs. Cr.	A2	2,265
Total	**Rs. Cr.**	**A=A1+A2**	**4,668**
Energy Sales	MUs	B	56,546
Transmission Charge	**Rs./Kwh**	**A*10/B**	**0.83**

7.4.9. The Commission does not segregate the ARR components of the DISCOMs into wires and supply business. Instead, for the computation of the wheeling charge for open access, the Commission assumes a fixed 9.56% of total ARR (including power purchase cost), as being towards Network establishment and operation cost.

Table 35: Haryana: Illustrative Ceiling Tariff - Distribution Wheeling Charge

Particulars	Units	Item	FY24
Distribution Wheeling ARR (9.56% of ARR)	Rs. Crore	A	3,752
Energy Sales	MUs	B	56,546
Distribution Wheeling charge	**Rs./kwh**	**A*10/B**	**0.66**

7.4.10. The total network cost for the state of Haryana, for FY 2023-24 is as follows:

Table 36: Haryana: Illustrative Ceiling Tariff - Network Cost

Particulars	Units	FY24
Transmission Network Cost	Rs./kwh	0.83
Distribution Wheeling Charge	Rs./kwh	0.66
Total Network Cost	**Rs./kwh**	**1.49**

Operating Cost (Supply)

7.4.11. Since segregated ARR for supply business of Haryana DISCOMs is not available, the Operating Cost is calculated as total ARR, less power purchase cost, less wheeling expenses (9.56% of total ARR) divided by energy sales.

Table 37: Haryana: Illustrative Ceiling Tariff - Operating Cost (Supply)

Particular	Units	Item	Value
Total ARR	Rs. Cr.	A	39,244
Less: Power Purchase Cost	Rs. Cr.	B	28,283
Less: Distribution Wheeling Expense	Rs. Cr.	C	3,752
Less: Transmission Expense	Rs Cr.	D	4,668
Operating Expense	**Rs. Cr.**	**E=A-B-C-D**	**2,541**
Energy Sales	MUs	F	56,546
Operating Cost (Supply)	**Rs./Kwh**	**E*10/F**	**0.45**

Headroom Margin

7.4.12. As discussed previously in the report, a fixed headroom of 10 paise/ unit may be allowed in the Operating Cost (supply) portion of the ceiling tariffs.

7.4.13. The overall illustrative ceiling tariff for the state of Haryana, post margins is as follows:

Table 38: Haryana - Illustrative Ceiling Tariffs

Particulars	Units	Item	FY24
Cost of Power	Rs./Kwh	A	5.00
Network Cost	Rs./Kwh	B	1.49
Operating Cost	Rs./Kwh	C	0.45
Headroom	Rs./Kwh	D	0.10
Less: NTI	Rs./Kwh	E	0.10
Ceiling Tariff	**Rs./Kwh**	**D=A+B+C+D-E**	**6.94**
120% of Ceiling			8.33
80% of Ceiling			5.55

Impact on DISCOM and Consumers

7.4.14. To assess the impact of ceiling tariff on DISCOM, the illustrative ceiling tariffs calculated is compared against the approved ACoS of DISCOMs as follows:

Table 39: Haryana: Illustrative ceiling tariffs - Impact on DISCOMs

Particulars	Units	FY24
Ceiling Tariff	Rs./Kwh	6.94
ACOS		

Particulars	Units	FY24
UHBVN	Rs./Kwh	6.57
DHBVN	Rs./Kwh	7.06
Overall	Rs./Kwh	6.84

7.4.15. To assess the impact of illustrative ceiling tariffs on consumers, the category wise Average Billing Rate (ABR) of DISCOMs is compared against the ±20% range of ceiling, as follows:

Table 40: Haryana: Illustrative ceiling tariffs - Impact on Consumers

Particulars	Units	FY24
Ceiling Tariff	Rs./Kwh	**6.94**
120% of Ceiling Tariff	Rs. /Kwh	8.33
80% of Ceiling Tariff	Rs. /Kwh	5.55
ABR, approved		
HT	Rs./Kwh	7.59
LT	Rs./Kwh	7.63

7.5. Tamil Nadu – Ceiling Tariff

7.5.1. TANGEDCO (Tamil Nadu Generation and Distribution Corporation Limited) functions as the primary electricity generation and distribution utility in the state of Tamil Nadu.

7.5.2. In September 2022, TNERC passed order for approval of True Up for the period from FY 2016-17 to FY 2020-21, Annual Performance Review for the FY 2021-22 and approval of Aggregate Revenue Requirement for the MYT period from FY 2022-23 to FY 2026-27. Accordingly, illustrative ceiling tariffs have been calculated for MYT period of FY 2022-23 to FY 2026-27.

7.5.3. Further in the above mentioned MYT order, the Commission has determined tariff for first year of the control period i.e. FY 2022-23 and approved an inflation linked methodology for annual revision of tariffs for years FY 2023-24 to FY 2026-27. As per the said methodology, the applicable tariff for ensuing years is calculated as prevailing tariff of previous year x (1 + % change in CPI of April month, over last year) or 6% whichever is lower. Based on the said approach, the Commission subsequently passed an order on 30th June 2023 for determination of tariff for FY 2023-24.

7.5.4. In line with methodology discussed previously in this report, the calculations of illustrative ceiling tariffs for the State of Tamil Nadu are detailed in subsequent paras.

Cost of Power

7.5.5. In the state of Tamil Nadu, power is purchased from outside sources as well as sourced from TANGEDCO's own generation plants. Approved cost of power from both these sources is considered for calculation of illustrative ceiling tariffs. These costs are adjusted for T&D losses, approved the Commission in its MYT order.

Table 41: Tamil Nadu: Illustrative Ceiling Tariff – Cost of Power

	FY 2022-23		FY 2023-24		FY 2024-25		FY 2025-26		FY 2026-27	
Particulars	*Energy mix*	*Value*	*Energy mix*	*Value*	*Energy mix*	*Value*	*Energy mix*	*Value*	*Energy mix*	*Value*
Power Purchase	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*	*%*	*Rs./ Kwh*

Particulars	FY 2022-23		FY 2023-24		FY 2024-25		FY 2025-26		FY 2026-27	
	Energy mix	*Value*	*Energy mix*	*Value*	*Energy mix*	*Value*	*Energy mix*	*Value*	*Energy mix*	*Value*
Thermal	43%	4.52	43%	4.49	43%	4.58	45%	4.61	56%	4.45
Wind	5%	3.12	5%	3.28	5%	3.28	5%	3.44	5%	3.61
Solar	9%	4.48	10%	4.48	11%	4.48	11%	4.48	11%	4.48
Other RE	0%	5.30	0%	5.53	0%	5.53	0%	5.71	0%	5.75
Others	15%	4.06	15%	4.27	15%	4.48	15%	4.70	15%	4.94
ST	28%	5.30	27%	5.27	26%	5.23	24%	5.14	13%	5.11
Sub-Total	100%	**4.61**	100%	**4.62**	100%	**4.67**	100%	**4.69**	100%	**4.58**
Own Generation										
Thermal	81%	6.93	81%	7.35	84%	6.43	85%	6.20	86%	5.90
Hydro	19%	3.15	19%	3.18	16%	3.21	15%	3.20	14%	3.22
Sub-Total	100%	**6.22**	100%	**6.57**	100%	**5.91**	100%	**5.74**	100%	**5.52**
Total		**5.06**		**5.16**		**5.05**		**5.01**		**4.87**
CTU Loss	%	1.69%		1.63%		1.57%		1.50%		1.44%
STU Loss	%	3.81%		3.81%		3.81%		3.81%		3.81%
Distribution Loss	%	11%		10%		10%		10%		10%
PPC Cost (Rs. Cr.)		51,780		52,745		54,871		57,078		58,026
Energy Sales (MUs)		86,166		89,882		93,740		97,936		102,342
PPC at Consumer Level (Rs./Kwh)		**6.01**		**5.87**		**5.85**		**5.83**		**5.67**

Network Cost

7.5.6. Transmission charges approved by the Commission for FY 2022-23 to FY 2026-27 (as per Tariff Order) are used for calculation of illustrative ceiling tariffs of Tamil Nadu. These costs are divided by per unit approved energy sales, to calculate per unit charge.

Table 42: Tamil Nadu - Illustrative Ceiling Tariff - Transmission Network Cost

Particulars	Units	FY 23	FY 24	FY 25	FY 26	FY 27
STU, CTU & SLDC charges	Rs. Cr.	7,901	8,547	9,535	10,527	11,494
Energy Sales	MUs	86,166	89,882	93,740	97,936	102,342
Transmission Charge	**Rs./Kwh**	**0.92**	**0.95**	**1.02**	**1.07**	**1.12**

7.5.7. For distribution wheeling charge, total ARR of Distribution business of TANGEDCO is segregated into wires and supply business ARR, using allocation norms as approved by the Commission. The wires business ARR is then divided by approved energy sales to calculate per unit distribution wheeling charge, as follows:

Table 43: Allocation Matrix for Allocation of Segregation of Accounts between Wires and Supply Business

Particulars	Distribution Wire Business (%)	Retail Supply Business (%)
Power Purchase Expenses	0%	100%
Inter-State Transmission Charges	0%	100%
Intra-State Transmission Charges	0%	100%
Operation & Maintenance Expenses	65%	35%
Depreciation	90%	10%
Interest on Long-term Loan Capital	90%	10%

Particulars	Distribution Wire Business (%)	Retail Supply Business (%)
Interest on Working Capital	10%	90%
Interest on Consumer Security Deposits	10%	90%
Income Tax	90%	10%
Return on Equity	90%	10%
Other Expenses	90%	10%

Table 44: Tamil Nadu - Illustrative Ceiling Tariff - Distribution Wheeling Charge

Particulars	Units	FY 23	FY 24	FY 25	FY 26	FY 27
Operation & Maintenance Expenses	Rs Crs	6,486	6,936	7,415	7,839	8,288
Depreciation	Rs Crs	1,427	1,646	1,854	2,085	2,170
Interest on Long-term Loan Capital	Rs Crs	4,147	4,486	4,880	4,936	4,848
Interest on Working Capital	Rs Crs	0.57	1.45	5.49	8.15	6.94
Total	Rs Crs	**12,061**	**13,069**	**14,155**	**14,868**	**15,312**
Energy Sales	MUs	86,166	89,882	93,740	97,936	102,342
Distribution Wheeling Charge	**Rs./Kwh**	**1.40**	**1.45**	**1.51**	**1.52**	**1.50**

7.5.8. The overall network cost for illustrative Ceiling Tariffs for Tamil Nadu is as follows:

Table 45: Tamil Nadu - Illustrative Ceiling Tariff - Network Cost

Particulars	Units	FY 23	FY 24	FY 25	FY 26	FY 27
Transmission Network Charge	Rs./Kwh	0.92	0.95	1.02	1.07	1.12
Distribution Wheeling Charge	Rs./Kwh	1.40	1.45	1.51	1.52	1.50
Total Network Charge	**Rs./Kwh**	**2.32**	**2.40**	**2.53**	**2.59**	**2.62**

Operating Cost (Supply)

7.5.9. Similar to the calculation for Network Cost, the Operating Cost for supply side of the business is calculated as per allocation norms as approved by the Commission for supply business, as follows:

Table 46: Tamil Nadu - Illustrative Ceiling Tariff - Operating Cost

Particular	FY 23	FY 24	FY 25	FY 26	FY 27
Operation & Maintenance Expenses	3,493	3,734	3,993	4,221	4,462
Depreciation	159	182	206	231	241
Interest on Long-term Loan Capital	461	498	543	549	539
Interest on Working Capital	5	14	50	73	62
Total	**4,118**	**4,428**	**4,791**	**5,074**	**5,305**
Energy sales	86,166	89,882	93,740	97,936	102,342
Operating Cost (Rs./Kwh)	**0.48**	**0.49**	**0.51**	**0.52**	**0.52**

Headroom Margin

7.5.10. As discussed previously in the report, a fixed headroom of 10 paise/ unit may be allowed in the Operating Cost (supply) portion of the ceiling tariffs.

7.5.11. The overall illustrative ceiling tariff for the state of Tamil Nadu, post margins is as follows:

Table 47: Tamil Nadu- Illustrative Ceiling Tariffs

Particulars	Units	Item	FY23	FY24	FY25	FY26	FY27
Cost of Power	Rs./Kwh	A	6.01	5.87	5.85	5.83	5.67
Network Cost	Rs./Kwh	B	2.32	2.40	2.53	2.59	2.62
Operating Cost	Rs./Kwh	C	0.48	0.49	0.51	0.52	0.52
Headroom	Rs./Kwh	D	0.10	0.10	0.10	0.10	0.10
Less: NTI	Rs./Kwh	E	0.45	0.43	0.41	0.40	0.40
Ceiling Tariff	**Rs./Kwh**	D=A+B+C+D-E	**8.45**	**8.43**	**8.58**	**8.64**	**8.51**
120% of Ceiling			10.14	10.12	10.30	10.36	10.21
80% of Ceiling			6.76	6.75	6.87	6.91	6.81

Impact on DISCOM and Consumers

7.5.12. To assess the impact of ceiling tariff on DISCOM, the illustrative ceiling tariffs calculated is compared against the approved ACoS of DISCOM, as follows:

Table 48: Tamil Nadu: Illustrative ceiling tariffs - Impact on DISCOMs

Particulars	Units	FY23	FY24	FY25	FY26	FY27
Ceiling Tariff	Rs./Kwh	**8.45**	**8.43**	**8.58**	**8.64**	**8.51**
120% of Ceiling	Rs./Kwh	10.14	10.12	10.30	10.36	10.21
80% of Ceiling	Rs./Kwh	6.76	6.75	6.87	6.91	6.81
ACOS						
TANGEDCO	Rs./Kwh	8.35	8.33	8.48	8.54	8.41

7.5.13. To assess the impact of illustrative ceiling tariffs on consumers, the category wise Average Billing Rate (ABR) of DISCOM is compared against the ±20% range of ceiling, as follows:

Table 49: TANGEDCO: Illustrative ceiling tariffs - Impact on Consumers

Particulars	Units	FY23	FY24	FY25	FY26	FY27
Ceiling Tariff	Rs./Kwh	**8.45**	**8.43**	**8.58**	**8.64**	**8.51**
120% of Ceiling Tariff	Rs. Kwh	10.14	10.12	10.30	10.36	10.21
80% of Ceiling Tariff	Rs. Kwh	6.76	6.75	6.87	6.91	6.81
ABR, approved (wtd. avg.)						
Domestic (LT)	Rs./Kwh	8.98	9.34	9.71	10.10	10.50
Agricultural (LT)	Rs./Kwh	4.46	4.48	4.50	4.42	5.55
Commercial (LT)	Rs./Kwh	11.40	13.38	14.29	15.04	15.84
Industrial (HT)	Rs./Kwh	8.96	9.28	9.61	9.96	10.31

8. Roadmap for implementation

8.1.1. Some of the key activities that may be required to enable Ceiling Tariffs are as follows:

Wheeling and Supply account segregation	• Segregation of DISCOM accounts into wheeling and supply business, is required to accurately determine the network and operating costs in ceiling tariffs • With segregated costs, each of the cost item can be benchmarked/ indexed accordingly
Cross Subsidy rationalization	• It is observed that even after allowing a headroom, ABR of several sub-categories remain more than ceiling tariffs • Rationalization of cross subsidy within ±20%, in line with Tariff Policy, will ensure tariffs remain below or equal to ceiling
Detailed cost analysis for Headroom	• Reasons for price fluctuations or uncontrollable costs may vary from state to state • SERCs may conduct a detailed analysis for DISCOMs in their respective states/ region to calculate an appropriate level of headroom allowance in ceiling tariffs, based on historical trend of cost variation in past True-ups
Area applicability of Ceiling Tariffs	• SERCs may decide upon the area in which ceiling tariffs are to be applied, basis type of area falling in their jurisdiction: 1. Single DISCOM in entire state 2. Multiple DISCOMs but with uniform tariffs 3. Multiple Parallel License without uniform tariffs

8.1.2. SERCs may conduct detailed analysis for DISCOMs in their respective regions.

8.1.3. SERCs may determine the first ceiling tariffs, along with start of next control period for power distribution utilities in the State. In case, different DISCOMs have a different control period in the state, the Commission may decide on an year which is closer to start of control period of larger DISCOM in the state/ region (hence, impacting more consumers) or may decide upon an year based on availability of data.

Annexures

Data used for calculation of illustrative tariffs

Maharashtra

Annexure 1: Power Purchase Cost for FY 2023-24 and FY 2024-25 of MSEDCL, as approved by the Commission

Generators	Source	2023-24			2024-25		
		Energy Purchase (ex-bus) (MUs)	Total Cost (Rs. Crore)	Rate per unit of power procured (Rs/kWh)	Energy Purchase (ex-bus) (MUs)	Total Cost (Rs. Crore)	Rate per unit of power procured (Rs/kWh)
KAPP	Thermal	982.1	232.59	2.37	982.1	244.21	2.49
TAPP 1&2	Thermal	573.42	152.43	2.66	1,146.84	320.11	2.79
TAPP 3&4	Thermal	2,817.01	1,004.38	3.57	2,817.01	1,054.60	3.74
SSP	Thermal	1,213.26	248.75	2.05	1,213.26	248.75	2.05
Pench	Thermal	136.89	28.06	2.05	136.89	28.06	2.05
Dodson I	Hydro	51.65	8.67	1.68	51.65	8.67	1.68
Dodson II	Hydro	64.39	19.01	2.95	64.39	24.29	3.77
Subhansari Hydro	Hydro	774.75	348.64	4.5	774.75	348.64	4.5
Renewable - Non-Solar#	Other RE	16,083.16	8,097.48	5.03	16,283.50	8,077.09	4.96
Renewable – Solar#	Solar	14,684.62	5,056.14	3.44	19,115.41	6,464.53	3.38
Hydro*	Hydro	4,285.91	822.39	1.92	4,285.91	835.79	1.95
BHUSAWAL – 3	Thermal	1,198.97	701.66	5.85	1,164	697	5.99
BHUSAWAL 4 & 5	Thermal	7,018.42	3,636.17	5.18	7,018	3,675	5.24
BHUSAWAL 6	Thermal				-	-	-

Generators	Source	2023-24 Energy Purchase (ex-bus) (MUs)	2023-24 Total Cost (Rs. Crore)	2023-24 Rate per unit of power procured (Rs/kWh)	2024-25 Energy Purchase (ex-bus) (MUs)	2024-25 Total Cost (Rs. Crore)	2024-25 Rate per unit of power procured (Rs/kWh)
KHAPARKHEDA -1 to 4	Thermal	4,755.87	2,597.76	5.46	4,583	2,574	5.62
KHAPARKHEDA 5	Thermal	3,509.21	1,954.66	5.57	3,509	1,989	5.67
NASHIK- 3 to 5	Thermal	3,497.91	2,097.14	6	2,458	1,633	6.65
CHANDRAPUR - 3 to 7	Thermal	10,564.48	5,315.55	5.03	10,564	5,462	5.17
Chandrapur 8 & 9	Thermal	7,018.42	3,629.68	5.17	7,018	3,644	5.19
Paras - 3 & 4	Thermal	3,334.26	1,618.57	4.85	3,334	1,733	5.2
PARLI UNIT-6 & 7	Thermal	-	462.65	-	-	482	-
KORADI – 6	Thermal	1,184.57	691.64	5.84	1,185	707	5.97
Koradi 8 to 10	Thermal	11,719.50	5,559.84	4.74	11,720	5,626	4.8
Parli replacement U 8	Thermal	-	384.03	-	-	385	-
GTPS URAN	Thermal	-	122.34	-	-	128	-
KSTPS	Thermal	4,498.25	1,078.12	2.4	4,498	1,112	2.47
KSTPS VII	Thermal	880.62	240.92	2.74	881	243	2.76
KhSTPS II	Thermal	1,036.52	487.38	4.7	1,037	490	4.73
VSTP I	Thermal	3,010.05	799.16	2.65	3,010	823	2.73
VSTP II	Thermal	2,410.54	551.66	2.29	2,411	566	2.35
VSTP III	Thermal	1,983.55	517.67	2.61	1,984	525	2.65
VSTP IV	Thermal	2,139.80	669.14	3.13	2,140	678	3.17
VSTP V	Thermal	1,153.01	417.2	3.62	1,153	434	3.76
SIPAT TPS 1	Thermal	4,057.95	1,390.05	3.43	4,058	1,429	3.52
SIPAT TPS 2	Thermal	1,975.04	717.31	3.63	1,975	741	3.75
MSTPS-I	Thermal	1,692.94	1,324.22	7.82	-	543	-
MSTPS-II	Thermal	-	580.72	-	-	586	-
Gadarwara - I & II	Thermal	668.62	355.46	5.32	363	228	6.29

Generators	Source	2023-24 Energy Purchase (ex-bus) (MUs)	2023-24 Total Cost (Rs. Crore)	2023-24 Rate per unit of power procured (Rs/kWh)	2024-25 Energy Purchase (ex-bus) (MUs)	2024-25 Total Cost (Rs. Crore)	2024-25 Rate per unit of power procured (Rs/kWh)
Lara Chattisgarh - Stg. I - I & II	Thermal	1,967.79	746.97	3.8	1,968	768	3.9
Khargone - I & II	Thermal	-	70.34	-	-	69	-
Solapur - I & II	Thermal	-	973.08	-	-	973	-
KAWAS	Thermal	-	136.05	-	-	138	-
GANDHAR	Thermal	-	169.25	-	-	172	-
IPP – JSW	Thermal	-	164.67	-	-	193	-
Mundra UMPP	Thermal	1,518.07	1,189.97	7.84	1,361	1,132	8.31
Adani power 125 MW	Thermal	434.62	325.21	7.48	362	274	7.57
Adani power 1320 MW	Thermal	9,215.03	4,413.69	4.79	9,215	4,498	4.88
Adani power 1200 MW	Thermal	1,084.92	1,642.42	15.14	1,063	1,448	13.63
Adani power 440 MW	Thermal	15.98	430.24	269.18	53	441	83.77
GMR Warora/ EMCO	Thermal	1,373.82	551.03	4.01	1,374	556	4.05
Rattanindia Amravati	Thermal	8,242.91	3,319.58	4.03	8,243	3,383	4.1
Sai Wardha	Thermal	1,551.61	748.53	4.82	1,552	757	4.88
PGCIL		-	3,845	-	-	4,037	-
Total		**146,380**	**72,645**	**4.96**	**1,48,122**	**73,629**	**4.97**

Annexure 2: Power Purchase Cost for FY 2023-24 and FY 2024-25 of TATA Power, as approved by the Commission

Particulars	Source	Approved for 2023-24 Quantum (MU)	Approved for 2023-24 Cost (Rs. Crore)	Approved for 2023-24 Rate (Rs./ kWh)	Approved for 2024-25 Quantum (MU)	Approved for 2024-25 Cost (Rs. Crore)	Approved for 2024-25 Rate (Rs./ kWh)
Unit-5	Thermal	1,374.92	1,171.88	7.44	1374.92	1022.88	7.44

Particulars	Source	Approved for 2023-24			Approved for 2024-25		
		Quantum (MU)	Cost (Rs. Crore)	Rate (Rs./ kWh)	Quantum (MU)	Cost (Rs. Crore)	Rate (Rs./ kWh)
Unit-7	Thermal	540.76	437.18	6.62	540.76	357.87	6.62
Unit-8	Thermal	744.60	674.39	7.3	1374.92	543.61	7.3
Bhira	Thermal	432.89	72.54	0.92	439.66	41.27	0.92
Bhivpuri	Thermal	140.79	50.40	2.15	140.79	31.12	2.15
Khopoli	Thermal	135.97	81.26	3.69	135.97	51.48	3.69
Non-Solar RE Purchase	Other RE	344.05	126.34	3.67	331.08	122.78	3.71
Solar RE purchase	Solar	1002.16	306.68	3.06	1002.16	306.68	3.06
Additional RE purchase	Other RE	700	343	4.90			
Bilateral	ST	365.25	187.37	5.13	1342.02	688.46	5.13
UI Purchase							
Outside Licence Area Sale							
Standby Purchase						103.52	
Stand-by Charges			103.53			329.57	
Transmission Charges			277				
SLDC Charges			1.02			1.09	
Total Power Purchase		**5,781.39**	**3,832.59**	**6.63**	**6,682.28**	**3,600.33**	**5.39**

Annexure 3:Power Purchase Cost for FY 2023-24 and FY 2024-25 of Adani Power, as approved by the Commission

Particulars	Source	Approved for 2023-24			Approved for 2024-25		
		Quantum (MU)	Cost (Rs. Crore)	Rate (Rs./ kWh)	Quantum (MU)	Cost (Rs. Crore)	Rate (Rs./ kWh)
ADTPS	Solar	3,684.24	1,845.31	5.01	3678.82	1816.96	4.94

Particulars	Source	Approved for 2023-24			Approved for 2024-25		
		Quantum (MU)	Cost (Rs. Crore)	Rate (Rs./ kWh)	Quantum (MU)	Cost (Rs. Crore)	Rate (Rs./ kWh)
DSPPL	Thermal	52.2	53.77	10.3	52.02	53.59	10.3
Existing sources Nonsolar	Other RE	87.63	49	5.59	86.87	48.64	5.6
Wind-Solar Hybrid	Solar	1,715.10	555.69	3.24	1,711.11	554.40	3.24
Wind-Solar Hybrid	Hydro	1,715.10	555.69	3.24	1,711.11	554.40	3.24
MTPP	Thermal	4,392.00	2,307.34	5.25	2,364.00	1,241.93	5.25
RE RTC Thermal	Thermal				2,879.88	1,411.14	4.9
Short term purchase	ST	730.54	374.77	5.13	915.79	469.8	5.13
Surplus	Thermal	-1,214.96	-623.27	5.13	-1,230.48	-631.24	5.13
RE procurement under short term	Other RE	525.6	257.54	4.9			
Banking		846	-		1,326.60	355.32	
Transmission chares			490.65			588.54	
SLDC charges			1.82			1.94	
Standby charges			184.89			184.86	
Total		**12,533.45**	**6,053.21**	**4.83**	**13495.72**	**6650.28**	**4.93**

Annexure 4: Power Purchase Cost for FY 2023-24 and FY 2024-25 of BEST, as approved by the Commission

Particulars	Source	FY 2023-24			FY 2024-25		
		Quantum (MU)	Cost (Rs. Cr)	Rate (Rs./kWh)	Quantum (MU)	Cost (Rs. Cr)	Rate (Rs./kWh)
TPC-G	Thermal	3,231.37	2,293.36	7.1	3,178.80	2,300.83	7.24
Past Gap Approved of TPC-G passed on to DISCOM			-200.5		31.48	26.95	8.56
Walwhan Solar MH Ltd	Solar	31.59	27.04	8.56	744.6	330.05	4.43
Manikaran Power Limited	Hydro	746.64	324.76	4.35			

Particulars	Source	FY 2023-24			FY 2024-25		
		Quantum (MU)	Cost (Rs. Cr)	Rate (Rs./kWh)	Quantum (MU)	Cost (Rs. Cr)	Rate (Rs./kWh)
Sai Wardha							
Short term Sources							
Solar Energy	Solar	430.43	210.91	4.9	485.11	237.7	4.9
Non-Solar Energy	Other RE	506.01	247.95	4.9	489.76	239.98	4.9
SECI Hybrid – Solar (Tranche III)	Solar				122.69	30.43	2.48
SECI Hybrid – Wind (Tranche III)	Wind				46.47	11.53	2.48
New Contract RTC/Bilateral	ST	198.58	147.54	7.43			
DAM	ST				315.59	161.9	5.13
Stand By Charges			94.03			94.01	
Past Period Pool Imbalance			61.97				
Intra State Transmission Charges			232.1			299.32	
MSLDC Charges			0.93			0.99	
Total		**5,144.61**	**3,440.08**	**6.69**	**5,414.52**	**3,733.69**	**6.9**

Annexure 5: Aggregate Revenue Requirement for FY 2023-24 of MSEDCL, as approved by the Commission (Rs. Crores)

Particulars	MYT Order	MTR Petition	Approved in this Order
Power Purchase Expenses	64,554.92	75,168.09	72,645.22
Operation & Maintenance Expenses	7,824.87	8,382.69	8,242.55
Depreciation	3,122.45	3,080.11	2,762.36
Interest on Loan Capital	893.88	935.03	826.17
Interest on Working Capital	145.69	138.35	125.75
Interest on Consumer Security Deposit	625.79	460.00	424.66
Other Finance Charges	-		
Provision for bad and doubtful debts	732.63	1,111.06	730.52

Particulars	MYT Order	MTR Petition	Approved in this Order
Other Expenses	60.87	329.80	60.87
Income Tax			
Intra-State Transmission Charges MSLDC	6,009.51	6,009.51	8,593.72
Incentives/Discounts	373.20	385.73	385.73
Contribution to contingency reserves	185.35	174.06	-
Opex schemes	110.49	652.51	84.45
DSM Expenses	-		
Return on equity capital	2,334.28	1,976.27	1,946.35
RLC refund	-	-	-
Additional surcharge refund	-	180.00	180
Effect of sharing of gains/losses	-	-	-
Past period adjustment by Commission	-	-	-
Revenue gap recovery allowed	5,585.00	5,585.00	5,585.00
Impact of payment to MPECS in future years	28.13	28.13	28.13
Incremental Consumption Rebate	426.45	426.45	426.45
Aggregate Revenue Requirement	93,013.50	1,05,022.80	1,03,047.93
Revenue from sales of Power	91,883.00	90,422.16	90,741.92
Non-Tariff Income	439.60	333.86	333.86
Income from open Access charges	214.76	214.76	214.76
Income from Trading of Surplus Power	363.02	-	-
Income from Wheeling charges			-
Income from Additional surcharges	112.63	112.63	112.63
Total Revenue	93,013.01	91,083.40	91,403.17
Revenue Gap	0.49	13,939.39	11,644.76
Energy Sales			1,26,533
ACOS			8.09

Annexure 6: Aggregate Revenue Requirement for FY 2024-25 of TATA Power, as approved by the Commission (Rs. Crores)

Particulars	MYT Order	MTR Petition	Approved in this Order
Power Purchase Expenses	66,819.60	77,448.70	73,628.95
Operation & Maintenance Expenses	8,124.87	8,806.78	8,659.55
Depreciation	3,183.82	3,308.73	2,820.60
Interest on Loan Capital	659.04	1,116.05	670.11
Interest on Working Capital	145.64	163.35	127.18
Interest on Consumer Security Deposit	657.08	483.00	445.90
Other Finance Charges	-		
Provision for bad and doubtful debts	732.63	1,165.80	730.52
Other Expenses	63.91	346.29	63.91
Income Tax			
Intra-State Transmission Charges MSLDC	6,036.77	6,036.77	8,638.78
Incentives/Discounts	391.86	405.02	405.02
Contribution to contingency reserves	190.57	200.22	-
Opex schemes	110.49	2,367.12	120.45
DSM Expenses	-		
Return on equity capital	2,398.04	1,992.41	1,951.47
RLC refund	-	-	-
Additional surcharge refund	-	180.00	180.00
Effect of sharing of gains/losses	-	-	-
Past period adjustment by Commission	-	-	-
Revenue gap recovery allowed	7,017.00	7,017.00	7,017.00
Impact of payment to MPECS in future years	21.14	21.14	21.14
Incremental Consumption Rebate	548.77	548.77	548.77
Aggregate Revenue Requirement	97,101.23	1,11,607.15	1,06,029.35
Revenue from sales of Power	95,927.00	92,354.58	92,354.94
Non-Tariff Income	461.59	350.55	350.55
Income from open Access charges	216.60	216.60	216.60

Particulars	MYT Order	MTR Petition	Approved in this Order
Income from Trading of Surplus Power	386.30	-	-
Income from Wheeling charges			-
Income from Additional surcharges	109.46	109.46	109.46
Total Revenue	97,100.95	93,031.20	93,031.55
Revenue Gap	0.28	18,575.96	12,997.80
Sales			129,399
ACOS			8.14

Annexure 7: Aggregate Revenue Requirement for FY 2023-24 and 2024-25 of Adani, as approved by the Commission (Rs. Crores)

Particulars	FY 2023-24	FY 2024-25
Power Purchase Expenses (including Inter State Transmission Charges)	5,560.73	6,059.79
Operation & Maintenance Expenses	1,470.20	1,533.42
Depreciation	436.15	469.50
Interest on Loan Capital	219.63	224.38
Interest on Working Capital	46.70	55.40
Interest on Consumer Security Deposit	53.91	55.55
Bad debts written off	14.37	14.37
Contribution to contingency reserves	1.47	1.68
Intra-State Transmission Charges	490.65	588.54
MSLDC Fees & Charges	1.82	1.94
Total Revenue Expenditure	8,295.63	9,004.57
Add: Return on Equity Capital	568.83	606.46
Aggregate Revenue Requirement	8,864.46	9,611.02
Less: Non-Tariff Income	215.96	226.76
True up surplus of AEML-G	-47.48	
Less: Income from other business	3.60	3.96
ARR adjustment due to amount received against sale of Santacruz land to RInfra	398.68	

Particulars	FY 2023-24	FY 2024-25
Aggregate Revenue Requirement	8,198.73	9,380.30
Energy Sales	10,985.51	11,819.43
ACOS (Rs/kWh)	8.57	8.76

Annexure 8: Aggregate Revenue Requirement for FY 2023-24 and 2024-25 of BEST, as approved by the Commission (Rs. Crores)

Particulars	FY 2023-24	FY 2024-25
Power Purchase Expenses (including Inter-State Transmission Charges)	3,207.05	3,433.38
Operation & Maintenance Expenses	662.13	690.07
Depreciation	112.63	116.71
Interest on Loan Capital	-	-
Interest on Working Capital	6.96	7.75
Interest on Consumer Security Deposit	26.82	26.82
Provision for bad and doubtful debts	7.97	7.97
Contribution to contingency reserves	-	-
Intra-State Transmission Charges	232.10	299.32
MSLDC Fees & Charges	0.93	0.99
Other Expenses	24.19	24.19
Total Revenue Expenditure	4,280.79	4,607.21
Add: Return on Equity Capital	143.82	148.72
Add: Return on Internal fund	5.28	5.28
Aggregate Revenue Requirement	4,429.89	4,761.20
Less: Non-Tariff Income	60.36	62.17
Aggregate Revenue Requirement from Retail Tariff	4,369.53	4,699.03
Past Revenue Gap of MYT Order Adjusted	(172.70)	(103.35)
ARR from Distribution Business with Revenue Gap	4,196.83	4,595.68
Past Revenue Gap	328.43	

Particulars	FY 2023-24	FY 2024-25
Energy Sales	4,772.81	5,023.20
ACOS	9.48	9.15

Annexure 9: Average Billing Rate (ABR) and Cross Subsidy Trajectory as approved by Commission for FY 2023-24 for MSEDCL

Category	Projected Average Cost of Supply (Rs/kWh)	Average Billing Rate (Rs/Unit)		Ratio of Average Billing Rate to Projected Average Cost of Supply (%)	
		Existing Tariff for FY 2022-23	Tariff for FY 2023-24	Existing Tariff for FY 2022-23	Tariff for FY – 2023-24
HT I – (A): HT - Industry	8.46	9.62	9.69	115%	115%
H – II: HT - Commercial		15.05	15.03	178%	178%
HT – III: HT - Railways/Metro/Monorail Traction		9.6	9.65	115%	114%
H – IV: HT - Public Water Works (PWW)		8.67	8.91	103%	105%
– T V: HT - Agriculture Pumps		5.94	6.5	60%	77%
H – VI: HT - Group Housing Societies (Residential)		8.31	8.64	97%	102%
HT V – II : HT - Public Services		11.72	12.08	146%	143%
HT Total		9.69	9.78	115%	116%
– T I: LT - Residential		8.39	8.9	102%	105%
L – II: LT - Non-Residential		13.18	13.03	154%	154%
LT – III: LT - Public Water Works (PWW)		5.34	5.85	61%	69%
L – IV: LT - Agriculture Metered		4.25	4.65	51%	55%
L – V : LT - Industry		9.38	9.25	117%	109%
L – VI: LT - Street Light		9.07	9.28	95%	110%
LT VII - Public Services		9.51	10.1	114%	119%
LT Total		7.41	7.79	90%	92%

Annexure 10: Revenue from revised Tariffs effective from 1 April, 2023 for MSEDCL

Category	No. of consumers	Sales in MU/ MVAh #	Contract Demand in KVA/MVA	Full year revenue (Rs. Crore)					Average Billing Rate (Rs/kWh)
				Fixed / Demand Charge	Energy Charge	Wheeling Charge	ToD Charges	Net Revenue	
HT Category									
HT I(A): HT - Industry (General)	14,580	40,337	92,20,659	5,521	32,736	1,653	-827.71	39,083	9.69
HT I(C): HT - Industry (Seasonal)	601	189	75,059	45	160	11	-2.32	213	11.27
HT I - Industry (Sub-Total)	15,181	40,527	92,95,718	5,566	32,896	1,664	-830.03	39,297	9.7
HT II: HT – Commercial	3,180	2,066	5,75,010	344	2,650	120	-8.1	3,106	15.03
HT III: HT - Railways/Metro/Monorail Traction	111	126	35,375	21	95	6	-	122	9.65
HT IV: HT - Public Water Works (PWW)	1,042	1,957	3,31,772	199	1,474	110	-37.48	1,745	8.91
HT V(A): HT - Agriculture Pumpsets	957	901	4,00,887	42	474	21	-	537	5.96
HT V(B)): HT - Agriculture Others	459	289	83,456	9	210	17	-	236	8.17
HT VI: HT - Group Housing Societies (Residential)	252	240	54,893	26	167	14	-	207	8.64
HT VIII(A): HT - Public Services-Government	421	352	84,296	50	336	21	-4.11	403	11.45
HT VIII(B): HT - Public Services-Others	1,145	887	2,27,236	136	922	47	-11.34	1,094	12.33
HT - MSPGCL-Aux Supply	30	439	2,40,724	-	-	-	-	-	-
HT IX: HT – Electric Vehicle Charging Station	14	59	37,344	3	41	4	-	48	8.06
Sub-Total HT Category	**22,790**	**47,844**	**1,13,66,709**	**6,398**	**39,265**	**2,024**	**-891.05**	**46,795**	**9.78**
LT Category									
LT I(A): LT - Residential-BPL Category (0-30 units)	1,93,366	59	30,024	7	9	-	-	16	2.72
LT I(B): LT - Residential	-	-	2,46,53,162	-	-	-	-	-	-
0-100	1,38,29,046	16,965	-	1,925	7,484	1,989	-	11,398	6.72
101-300	50,23,062	6,987	-	699	6,733	819	-	8,251	11.81
301-500	8,17,300	1,072	-	114	1,460	126	-	1,699	15.85
Above 500	2,96,470	1,171	-	41	1,823	137	-	2,001	17.1
Three Phase Connection	-	-	-	-	-	-	-	-	-
LT I: LT - Residential (Sub-Total)	**2,01,59,243**	**26,255**	**2,46,83,186**	**2,786**	**17,509**	**3,071**	**-**	**23,366**	**8.9**

Category	No. of consumers	Sales in MU/ MVAh #	Contract Demand in KVA/MVA	Full year revenue (Rs. Crore)					Average Billing Rate (Rs/kWh)
				Fixed / Demand Charge	Energy Charge	Wheeling Charge	ToD Charges	Net Revenue	
LT II(A): LT - Non-Residential (0-20 kW)	19,08,815	4,954	40,06,985	1,077	4,097	581	-	5,755	11.62
LT II(B): LT - Non-Residential (>20 kW and ≤ 50 kW)	23,939	907	3,51,239	198	1,145	106	2.15	1,452	16.01
LT II(C): LT - Non-Residential (Above 50 kW)	6,066	872	2,81,880	159	1,302	102	3.69	1,566	17.97
LT II: LT - Non-Residential (Sub-Total)	19,38,819	6,732	46,40,103	1,434	6,544	789	5.85	8,773	13.03
LT III(A): LT - Public Water Works (0-20 kW)	52,897	672	1,10,272	15	238	79	-	332	4.94
LT III(B): LT - Public Water Works (>20 kW-40 kW)	1,091	106	31,619	5	58	12	-	76	7.17
LT III (C): LT - Public Water Works (Above 40 kW)	555	149	39,954	8	108	17	-	134	9.02
LT III: LT - Public Water Works (Sub-Total)	54,542	926	1,81,846	29	404	109	-	542	5.85
LT IV(A): LT - AG Un-metered-Pumpsets (Category 1 Zones)	0	-	-	-	-	-	-	-	
(a) 0 - 5 HP	555908	2,337	27,86,735	1,561	-	391	-	1,953	
(b) > 5 HP - 7.5 HP	131244	335	6,57,917	398	-	92	-	490	
(c) Above 7.5 HP	0	60	-	-	-	-	-	-	
LT IV(A): LT - AG Un-metered-Pumpsets (Category 2 Zones)	-	-	-	-	-	-	-	-	
(a) 0 - 5 HP	5,84,163	5,205	29,28,372	1,267	-	411	-	1,678	
(b) > 5 HP - 7.5 HP	1,98,401	744	9,94,572	471	-	140	-	611	
(c) Above 7.5 HP	-	36	-	-	-	-	-	-	
LT IV(A): LT - AG Un-metered-Pumpsets (Sub-Total)									
LT IV(B): LT -AG Metered-Pumpsets	27,82,070	18,429	1,54,15,399	869	5,533	2,160	-	8,563	4.65
LT IV(C): LT - AG Metered-Others	28,709	235	2,68,727	42	119	28	-	188	8
LT IV - LT - Agriculture (Sub-Total)	42,80,495	27,382	2,30,51,722	4,608	5,652	3,222	-	13,482	4.92
LT V (A): LT - Industry - Powerlooms									
(i): 0-20 kW	29,754	412	1,33,735	19	240	48	-	307	7.46
(ii): Above 20 kW	4,670	1,584	2,74,611	116	1,094	186	-34.37	1,362	8.6
LT V (A): LT - Industry - Powerlooms Total	34,424	1,996	4,08,346	135	1,334	234	-34.37	1,669	8.36

Category	No. of consumers	Sales in MU/ MVAh #	Contract Demand in KVA/MVA	Full year revenue (Rs. Crore) Fixed / Demand Charge	Energy Charge	Wheeling Charge	ToD Charges	Net Revenue	Average Billing Rate (Rs/kWh)
LT V(B): LT - Industry - General	-								
(i): 0-20 kW	2,59,589	3,074	26,69,943	165	1,837	360	-	2,362	7.69
(ii): Above 20 kW	61,646	4,734	22,75,444	964	3,353	555	-10.84	4,861	10.27
LT V(B): LT - Industry - General Total	3,21,235	7,808	49,45,387	1,129	5,190	915	-10.84	7,224	9.25
LT V: LT - Industry Total	3,55,659	9,804	53,53,733	1,264	6,524	1,149	-45.21	8,892	9.07
LT VI (A) Street Light-Gram Panchayat, A,B&C Class MCs	68,378	553	2,88,654	45	367	65	-	476	8.61
LT VI (B) Street Light - Municipal Corporation Areas	29,811	343	2,48,735	39	277	40	-	356	10.36
LT VI Street Light (Sub-Total)	98,188	896	5,37,390	83	644	105	-	832	9.28
LT VII (A) Public Services-Government									
(i) 0-20 kW	41,394	58	62,452	19	24	7	-	50	8.64
(ii) 20 kW-50 kW	485	13	6,968	3	8	1	-0.19	12	9.53
(iii) Above 50 kW	200	16	9,667	5	12	2	-0.15	18	11.36
LT VII (A) Public Services-Government (Sub-Total)	42,078	86	79,087	27	43	10	-0.34	80	9.27
LT VII (B) Public Services-Others									
(i) 0-20 kW	68,103	345	2,49,126	34	205	40	-	280	8.11
(ii) 20 kW-50 kW	2,604	130	51,637	26	122	15	-0.96	163	12.51
(iii) Above 50 kW	1,275	185	60,081	30	180	22	-1.18	231	12.49
LT VII (B) Public Services-Others (Sub-Total)	71,981	660	3,60,843	91	507	77	-2.15	674	10.2
LT VII Public Services	1,14,059	747	4,39,930	118	551	88	-2.48	754	10.1
LT VIII – Electric Vehicle Charging Station	330	2	9,100	1	1	0	0.02	2	11
Sub-Total LT Category	2,70,01,334	72,745	5,88,97,009	10,324	37,829	8,533	-41.83	56,643	7.79
Distribution Franchisees									
Bhiwandi	-	3,892	-	-	-	-	-	2,592	6.66
Thane	-	770	-	-	-	-	-	529	6.86
Malegaon	-	1,281	-	-	-	-	-	697	5.44

Category	No. of consumers	Sales in MU/ MVAh #	Contract Demand in KVA/MVA	Full year revenue (Rs. Crore)					Average Billing Rate (Rs/kWh)
				Fixed / Demand Charge	Energy Charge	Wheeling Charge	ToD Charges	Net Revenue	
Stand By Charges	-	-	-	-	396	-	-	396	-
LF/ Incentives/Discount	-	-	-	-	-605	-	-	-605	-
MSEDCL Total Revenue	**2,70,24,124**	**1,26,533**	**7,02,63,718**	**16,721**	**76,884**	**10,557**	**-932.88**	**1,07,047**	**8.46**

Annexure 11: Average Billing Rate (ABR) and Cross Subsidy Trajectory as approved by Commission for FY 2024-25 for MSEDCL

Category	Projected Average Cost of Supply (Rs/kWh)	Average Billing Rate (Rs/Unit)		Ratio of Average Billing Rate to Projected Average Cost of Supply (%)	
		Tariff for FY 2023-24	Tariff for FY 2024-25	Tariff for FY 2023-24	Tariff for FY – 2024-25
HT I – (A): HT - Industry	8.94	9.69	10.09	115%	113%
H – II: HT - Commercial		15.03	15.58	178%	174%
HT – III: HT - Railways/Metro/Monorail Traction		9.65	10.11	114%	113%
H – IV: HT - Public Water Works (PWW)		8.91	9.25	105%	104%
– T V: HT - Agriculture Pumps		6.5	7.12	77%	80%
H – VI: HT - Group Housing Societies (Residential)		8.64	8.96	102%	100%
HT V – II : HT - Public Services		12.08	12.74	143%	143%
HT Total		**9.78**	**10.18**	**116%**	**114%**
– T I: LT - Residential		8.9	9.47	105%	106%
L – II: LT - Non-Residential		13.03	13.51	154%	151%
LT – III: LT - Public Water Works (PWW)		5.85	6.56	69%	73%
L – IV: LT - Agriculture Metered		4.65	5.08	55%	57%

Category	Projected Average Cost of Supply (Rs/kWh)	Average Billing Rate (Rs/Unit)		Ratio of Average Billing Rate to Projected Average Cost of Supply (%)	
		Tariff for FY 2023-24	Tariff for FY 2024-25	Tariff for FY 2023-24	Tariff for FY – 2024-25
L – V : LT - Industry		9.25	9.64	109%	108%
L – VI: LT - Street Light		9.28	9.66	110%	108%
LT VII - Public Services		10.1	10.61	119%	119%
LT Total		**7.79**	**8.34**	**92%**	**93%**

Annexure 12: : Category-wise ABR and Tariff Increase/Decrease approved by Commission for FY 2023-24 and FY 2024-25 of BEST

Category	Average Billing Rate			% Tariff Increase/ Reduction	
	Existing *	Approved		Approved	
	FY 2022-23	FY 2023-24	FY 2024-25	FY 2023-24	FY 2024-25
HT Category					
HT - I Industry	8.06	9.16	9.66	13.59%	5.44%
HT - II Commercial	10.05	10.45	10.75	3.96%	2.92%
HT - III Group Housing	8.14	9.12	9.68	12.02%	6.11%
HT - IV (A) Railways	11.91	10.78	11.50	-9.47%	6.66%
HT - V (A) Public services (Govt. Hospital & Educational Institutions)	8.17	9.06	9.61	10.81%	6.13%
HT - V (B) Public services (Others)	8.93	9.77	10.58	9.42%	8.32%
HT - VI Electrical Vehicle	-	-	-	0.00%	0.00%
LT Category					
LT - I (B) Residential	3.06	3.46	3.73	12.89%	7.92%
LT - II (a) Commercial	7.31	7.76	8.29	6.19%	6.75%
LT - II (b) Commercial >20 & <=50 kW	9.01	9.97	10.53	10.71%	5.56%
LT - II (c) Commercial >50	10.88	11.40	11.90	4.79%	4.40%
LT - III (A) Industry (upto 20 kW)	11.06	11.46	12.17	3.62%	6.26%

Category	Average Billing Rate			% Tariff Increase/ Reduction	
	Existing *	Approved		Approved	
	FY 2022-23	FY 2023-24	FY 2024-25	FY 2023-24	FY 2024-25
LT-III (b) Industrial	7.35	8.33	9.14	13.32%	9.71%
LT - IV (A) Public Services - Govt. Hosp. & Edu. Institutions)	10.74	10.87	11.27	1.17%	3.69%
LT - IV (B) Public Services - Others	7.44	8.60	9.18	15.59%	6.80%
LT-V (A) Agriculture- Pumpsets	7.60	8.76	9.34	15.19%	6.59%
LT-V (B) Agriculture- Others	-	-	-	0.00%	0.00%
LT VI Vehicle Charging	7.08	6.80	7.49	-3.90%	10.17%

Annexure 13: Headroom in Operating Cost (Supply) - Variation in past Trued-Up Years

	FY20			FY21			FY22		
Particulars	MYT	True-up Filed	Trued-up approved	MYT	True-up Filed	Trued-up approved	MYT	True-up Filed	Trued-up approved
O&M expenses	3,332	3,351	3,326	3,390	3,365	3,305	3,304	3,577	3,514
Depreciation	311	290	271	333	378	378	357	341	339
Interest on Loan Capital	144	143	139	145	129	127	149	114	113
Interest on Working Capital	25	18	2	15	2,207	0	15	11	1
Interest on Consumer SD	816	772	772	544	302	301	571	367	367
Other Finance Charges	3	2	2	0	30	30	0	41	41
Provision for bad debts	678	785	549	678	441	441	678	430	430
Other Expenses	101	130	97	97	158	61	101	709	471
Income Tax	847	723	651	0	0	0	0	0	0
Incentives/Discounts	307	337	337	322	307	307	339	367	367
Contingency reserves	17	15	15	18	18	2	20	20	2
Return on Equity Capital	259	264	263	291	271	260	311	314	300
RLC refund	2	2	2	0	0	0	0	0	0
ASC refund	0	0	0	0	0	0	0	12	12
Past Period Surplus	853	853	853	0	0	0	0	0	0

	FY20			FY21			FY22		
Particulars	**MYT**	**True-up Filed**	**Trued-up approved**	**MYT**	**True-up Filed**	**Trued-up approved**	**MYT**	**True-up Filed**	**Trued-up approved**
Revenue Gap Recover	2,563	2,563	2,563	755	755	755	2,679	2,679	2,679
Impact of payment to MPECS	40	40	40	37	37	37	34	34	34
Opex scheme	0	0	0	26	18	18	26	23	23
Incremental Consumption Rebate	0	0	0	440	337	337	549	546	546
Standby Charges	99	99	99	100	100	100	100	100	100
DSM Expenses	1	1	1	1	0	0	1	1	1
Other Finance Charges	0	2	2	0	0	0	0	0	0
PF impact due to SC Judgment	0	0	0	0	0	0	0	0	0
Forex rate variation	0	0	0	0	0	0	0	0	0
Refinancing Charges	0	1	1	0	0	0	0	0	0
PV of interest cost saving	0	-1	-1	0	0	0	0	0	0
Payment to TPC-G	0	0	0	88	53	53	0	0	0
True-up Gap/(surplus) of AEMl-G	0	0	0	-92	-92	-92	0	0	0
Less: Non-tariff income	454	578	578	474	358	358	496	1,285	1,285
Total	9,944	9,813	9,407	6,715	8,457	6,063	8,737	8,402	8,056
Energy Sales (MUs)	119,860	121,242	116,264	133,621	124,647	117,924	138,480	138,771	130,004
Operating Cost (Supply), Rs./Kwh	0.83	0.81	0.81	0.50	0.68	0.51	0.63	0.61	0.62

Bihar

Annexure 14: Power Purchase Cost for FY 2023-24 as computed by Commission for NBPDCL

Sl.	Particulars	Source	Units (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs	Avg Tariff (Rs./Kwh
I	**Stations with injection at CTU**		**13,178.75**	**3,089.54**	**3,762.94**	**6,852.48**	**5.20**
1	FSTPP I &II	Thermal	868.37	129.42	341.27	470.69	5.42
2	FSTPP III	Thermal	185.98	51.48	73.09	124.57	6.70
3	KHSTPP I	Thermal	607.75	111.60	219.40	331.00	5.45
4	KHSTPP II	Thermal	129.11	24.40	46.61	71.01	5.50
5	Barh Stage I Unit I	Thermal	590.92	171.42	188.68	360.10	6.09
6	Barh Stage I Unit II	Thermal	590.92	171.42	188.50	359.92	6.09
7	Barh Stage I Unit III	Thermal	477.29	128.96	152.26	281.21	5.89
8	Barh Stage II	Thermal	2,070.26	815.44	660.41	1,475.85	7.13
9	Nabinagar (BRBCL) Unit I – III	Thermal	129.63	41.06	35.62	76.68	5.92
10	Nabinagar (BRBCL) Unit IV	Thermal	43.21	13.69	11.87	25.56	5.92
11	Talcher Stage I	Thermal	1,296.33	125.24	269.51	394.74	3.05
12	KBUNL Stage II	Thermal	505.36	250.16	147.72	397.88	7.87
13	NPGCL Unit I	Thermal	967.03	241.92	268.25	510.17	5.28
14	NPGCL Unit II	Thermal	967.03	241.92	268.25	510.17	5.28
15	NPGCL Unit III	Thermal	967.03	241.92	268.25	510.17	5.28
16	North Karanpura Unit I	Thermal	396.42	115.00	88.00	203.00	5.12
17	North Karanpura Unit II	Thermal	360.94	86.51	80.13	166.64	4.62
18	Darlipali STPS Unit I	Thermal	298.17	42.34	36.38	78.71	2.64
19	Darlipali STPS Unit II	Thermal	298.17	42.34	36.38	78.71	2.64
20	Chuka	Hydro	197.70		47.45	47.45	2.40
21	Rangit	Hydro	42.00	10.92	7.98	18.90	4.50
22	Tala	Hydro	520.23		112.37	112.37	2.16
23	Teesta	Hydro	216.86	32.42	25.16	57.58	2.65

Sl.	Particulars	Source	Units (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs	Avg Tariff (Rs./Kwh
24	Mangdechu	Hydro	452.03		189.40	189.40	4.19
II	**Stations with injection at STU**		**897.50**	**501.40**	**240.33**	**741.73**	**8.26**
1	BSPHC	Hydro	33.28		8.29	8.29	2.49
2	BTPS Stage II Unit I	Thermal	432.11	250.70	116.02	366.72	8.49
3	BTPS Stage II Unit II	Thermal	432.11	250.70	116.02	366.72	8.49
III	**IPPs**		**1,439.15**	**374.22**	**166.97**	**541.19**	**3.76**
1	GMR	Thermal	722.64	160.26	86.72	246.98	3.42
2	JITPL	Thermal	716.51	213.96	80.25	294.20	4.11
IV	**Renewables**		**2,781.92**		**845.80**	**845.80**	**3.04**
1	M/s Sunmark Energy Projects Limited (Formerly MBCEL)	Solar	7.62		5.35	5.35	7.02
2	M/s Response renewable Energy Ltd, Kolkata.	Solar	7.62		5.35	5.35	7.02
3	M/s Avantika Contractors Ltd., Hyderabad	Solar	3.81		2.93	2.93	7.69
4	M/s Glatt Solutions Pvt. Ltd, Kolkata.	Solar	2.29		1.60	1.60	7.01
5	Alfa Infraprop Pvt. Ltd.	Solar	15.24		12.00	12.00	7.87
6	Udipta Energy & Equipment Pvt. Ltd.	Solar	3.81		3.04	3.04	7.97
7	Azure Power India Pvt. Ltd.	Solar	7.62		6.40	6.40	8.40
8	Welspun Renewables Project – I	Solar	7.62		6.63	6.63	8.70
9	Welspun Renewables Project – II	Solar	11.43		9.88	9.88	8.64
10	Welspun Renewables Project – III	Solar	11.43		9.79	9.79	8.56
11	Acme Cleantech Project (Nalanda)	Solar	11.43		9.98	9.98	8.73
12	Acme Cleantech Project (Magadh)	Solar	7.62		6.65	6.65	8.73
13	Solar Energy Corporation of India Ltd., GOI	Solar	7.58		4.50	4.50	5.93
14	SECI Phase-II Solar	Solar	152.79		38.35	38.35	2.51
15	SECI Phase-III (Renew Sunwaves)	Solar	311.00		78.06	78.06	2.51
16	NTPC ISTS Solar	Solar	287.54		76.77	76.77	2.67
17	GRT Jewellars (SECI - V)	Solar	131.38		32.84	32.84	2.50
18	Wind ISTS Scheme Tranche I (PTC) (Greeen Infra, Inox, Mytrah & Ostro)	Wind	215.52		68.53	68.53	3.18

Sl.	Particulars	Source	Units (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs	Avg Tariff (Rs./Kwh
19	Wind ISTS Scheme Tranche II (SECI) (Orange)	Wind	107.76		29.20	29.20	2.71
20	SECI Green Infra	Solar	107.76		27.05	27.05	2.51
21	Alfanar	Wind	53.88		13.58	13.58	2.52
22	Betam	Wind	69.86		17.60	17.60	2.52
23	Adani Green (SECI -V)	Solar	161.77		44.65	44.65	2.76
24	Ecoren Energy (SECI - V)	Solar	80.85		22.39	22.39	2.77
25	Ostro Kannad	Wind	378.62		82.92	82.92	2.19
26	Morjar Windfarm	Wind	56.71		12.42	12.42	2.19
27	SBE Renewables (SECI Phase-V Solar)	Solar	310.74		84.52	84.52	2.72
28	BREDA Floating Solar Project	Solar	1.53		0.63	0.63	4.15
29	BREDA Solar Project	Solar	6.54		2.03	2.03	3.11
30	SECI Hybrid Project	Solar	20.13		8.09	8.09	4.02
31	New Swadeshi Sugar Mill, Narkataganj	Other RE	18.66		9.46	9.46	5.07
32	Hasanpur Sugar Mill, Dalsinghsarai	Other RE	27.05		16.83	16.83	6.22
33	Bharat Sugar Mills, Sidhwalia, Gopalganj	Other RE	27.98		14.05	14.05	5.02
34	Hari Nagar Sugar Mills, Hari Nagar, West Champaran	Other RE	27.05		13.74	13.74	5.08
35	HPCL Biofuels Ltd., Sugauli, East Champaran	Other RE	37.31		18.92	18.92	5.07
36	HPCL Biofuels Ltd., Lauria, West Champaran	Other RE	37.31		18.95	18.95	5.08
37	Riga Sugar Company Ltd.	Other RE	5.60		3.50	3.50	6.25
38	Siddhashram Rice Mill Cluster Pvt ltd	Other RE	2.71		1.96	1.96	7.23
39	Bihar Distillers & Bottlers Pvt ltd	Other RE	25.51		16.22	16.22	6.36
40	Tirupati Sugar	Other RE	13.24		8.42	8.42	6.36
V	**Others**						
1	PTC(IEX)	ST	82.49			42.89	
	Grand Total		**18,297.32**	**3,965.16**	**5,016.04**	**8,981.20**	**4.91**

Annexure 15: Power Purchase Costs for FY 2024-25 as approved by Commission for NBPDCL

SI.	Particulars	Source	Units considered (MU)	Fixed Cost (Rs.Crs)	Energy Cost(Rs Crs)	Total Cost Rs. Crs	Avg. Tariff (Rs./Kwh)
I	**Stations with injection at CTU**		**14201.61**	**2,872.98**	**3432.92**	**6305.9**	**4.44**
1	FSTPP III	Thermal	185.47	43.56	53.42	96.97	5.23
2	KHSTPP II	Thermal	234.11	21.99	53.38	75.37	3.22
3	Barh Stage I Unit I	Thermal	1071.46	171.42	272.15	443.57	4.14
4	Barh Stage I Unit II	Thermal	972.96	171.42	247.13	418.55	4.3
5	Barh Stage I Unit III	Thermal	589.3	171.42	149.68	321.1	5.45
6	Barh Stage II	Thermal	2064.61	600.56	606.99	1207.56	5.85
7	Nabinagar (BRBCL) Unit I – III	Thermal	129.28	43.82	38.4	82.21	6.36
8	Nabinagar (BRBCL) Unit IV	Thermal	43.09	14.61	12.8	27.4	6.36
9	KBUNL Stage II	Thermal	503.98	182.91	136.08	318.99	6.33
10	NPGCL Unit I	Thermal	1753.43	355.16	389.26	744.42	4.25
11	NPGCL Unit II	Thermal	1621.67	328.47	360.01	688.48	4.25
12	NPGCL Unit III	Thermal	1621.67	328.47	360.01	688.48	4.25
13	North Karanpura Unit I	Thermal	718.79	145.59	159.57	305.16	4.25
14	North Karanpura Unit II	Thermal	718.79	145.59	159.57	305.16	4.25
15	Darlipali STPS Unit I	Thermal	297.36	59.79	28.84	88.64	2.98
16	Darlipali STPS Unit II	Thermal	250.72	50.42	24.32	74.74	2.98
17	Chuka	Hydro	197.16	-	47.32	47.32	2.4
18	Rangit	Hydro	41.89	9.85	7.96	17.81	4.25
19	Tala	Hydro	518.81	-	112.06	112.06	2.16
20	Teesta	Hydro	216.27	27.93	25.09	53.02	2.45
21	Mangdechu	Hydro	450.79	-	188.88	188.88	4.19
II	**Stations with injection at STU**		**1274.26**	**347.02**	**365.62**	**712.65**	**5.59**
1	BSPHC	Hydro	33.19	-	8.26	8.26	2.49
2	KBUNL Stage I	Thermal					

SI.	Particulars	Source	Units considered (MU)	Fixed Cost (Rs.Crs)	Energy Cost(Rs Crs)	Total Cost Rs. Crs	Avg. Tariff (Rs./Kwh)
3	BTPS Stage I Unit I	Thermal	189.61	13.66	67.5	81.16	4.28
4	BTPS Stage I Unit II	Thermal	189.61	13.66	67.5	81.16	4.28
5	BTPS Stage II Unit I	Thermal	430.93	159.85	111.18	271.03	6.29
6	BTPS Stage II Unit II	Thermal	430.93	159.85	111.18	271.03	6.29
III	**IPPs**		**1529.4**	**335.91**	**177.1**	**513.01**	**3.35**
1	GMR	Thermal	814.85	138.74	97.78	236.52	2.9
2	JITPL	Thermal	714.56	197.17	79.32	276.49	3.87
IV	**Renewables**		**3210.76**	**-**	**1005.94**	**1005.94**	**3.13**
1	M/s Sunmark Energy Projects Limited (Formerly MBCEL)	Solar	7.58	-	4.3	4.3	5.67
2	M/s Response renewable Energy Ltd, Kolkata.	Solar	7.58	-	4.3	4.3	5.67
3	M/s Avantika Contractors Ltd., Hyderabad	Solar	3.79	-	2.91	2.91	7.69
4	M/s Glatt Solutions Pvt. Ltd, Kolkata.	Solar	2.27	-	1.29	1.29	5.67
5	Alfa Infraprop Pvt. Ltd.	Solar	15.16	-	11.93	11.93	7.87
6	Udipta Energy & Equipment Pvt. Ltd.	Solar	3.79	-	3.02	3.02	7.98
7	Azure Power India Pvt. Ltd.	Solar	7.58	-	6.36	6.36	8.39
8	Welspun Renewables Project – I	Solar	7.58	-	6.6	6.6	8.7
9	Welspun Renewables Project – II	Solar	11.37	-	9.82	9.82	8.64
10	Welspun Renewables Project – III	Solar	11.37	-	9.73	9.73	8.56
11	Acme Cleantech Project (Nalanda)	Solar	11.37	-	9.93	9.93	8.73
12	Acme Cleantech Project (Magadh)	Solar	7.58	-	6.62	6.62	8.73
13	Solar Energy Corporation of India Ltd., Government of India	Solar	7.54	-	4.15	4.15	5.5
14	SECI Phase-II	Solar	151.96	-	38.14	38.14	2.51
15	SECI Phase-III	Solar	309.31	-	81.04	81.04	2.62
16	NTPC ISTS Solar	Solar	286.04	-	76.37	76.37	2.67
17	Wind ISTS Scheme Tranche I (PTC) (Greeen Infra, Inox, Mytrah&Ostro)	Wind	214.37	-	75.67	75.67	3.53
18	Wind ISTS Scheme Tranche II (SECI) (Orange)	Wind	107.18	-	29.05	29.05	2.71

SI.	Particulars	Source	Units considered (MU)	Fixed Cost (Rs.Crs)	Energy Cost(Rs Crs)	Total Cost Rs. Crs	Avg. Tariff (Rs./Kwh)
19	SECI Green Infra	Solar	107.18	-	26.9	26.9	2.51
20	Torrent Power	Solar	74.45	-	20.18	20.18	2.71
21	Adani Green	Solar	64.31	-	17.49	17.49	2.72
22	Alfanar	Wind	53.59	-	13.51	13.51	2.52
23	Betam	Wind	69.49	-	17.51	17.51	2.52
24	Adani Green (V)	Solar	160.87	-	45.53	45.53	2.83
25	Boreas Renewable	Solar	250.21	-	70.81	70.81	2.83
26	OstroKannad	Wind	376.5	-	108.81	108.81	2.89
27	Morjar Windfarm	Wind	56.39	-	16.3	16.3	2.89
28	SECI Phase-V	Solar	449.59	-	120.94	120.94	2.69
29	BREDA Floating Solar Project	Solar	1.52	-	0.63	0.63	4.16
30	BREDA Solar Project	Solar	151.98	-	47.26	47.26	3.11
31	New Swadeshi Sugar Mill, Narkataganj	Other RE	18.56	-	9.43	9.43	5.08
32	Hasanpur Sugar Mill, Dalsinghsarai	Other RE	26.91	-	16.6	16.6	6.17
33	Bharat Sugar Mills, Sidhwalia, Gopalganj	Other RE	27.84	-	14.06	14.06	5.05
34	Hari Nagar Sugar Mills, Hari Nagar, West Champaran	Other RE	26.91	-	14.99	14.99	5.57
35	HPCL Biofuels Ltd., Sugauli, East Champaran	Other RE	37.11	-	13.77	13.77	3.71
36	HPCL Biofuels Ltd., Lauria, West Champaran	Other RE	37.11	-	20.26	20.26	5.46
37	Riga Sugar Company Ltd.	Other RE	5.57	-	3.48	3.48	6.25
38	Siddhashram Rice Mill Cluster Pvt ltd	Other RE	2.7	-	1.72	1.72	6.36
39	Bihar Distillers & Bottlers Pvt ltd	Other RE	25.37	-	16.14	16.14	6.36
40	Tirupati Sugar	Other RE	13.17	-	8.4	8.4	6.38
	Grand Total		**20216.03**	**3,555.91**	**4981.58**	**8537.49**	**4.22**

Annexure 16: Power Purchase Cost for FY 2023-24 as computed by Commission for SBPDCL

SI.	Particulars	Source	Units Considered (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs	Ave Cost Rs.
I	**Stations with injection at CTU**		**15,059.75**	**3,626.85**	**4,331.26**	**7,958.11**	**5.28**

Sl.	Particulars	Source	Units Considered (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs	Ave Cost Rs.
1	FSTPP I &II	Thermal	1,019.39	151.93	400.62	552.54	5.42
2	FSTPP III	Thermal	218.32	60.43	85.80	146.23	6.70
3	KHSTPP I	Thermal	713.45	131.01	257.55	388.57	5.45
4	KHSTPP II	Thermal	151.57	28.64	54.72	83.36	5.50
5	Barh Stage I Unit I	Thermal	693.69	201.23	221.49	422.72	6.09
6	Barh Stage I Unit II	Thermal	560.30	201.23	178.74	379.97	6.78
7	Barh Stage I Unit III	Thermal	693.69	151.38	221.29	372.67	5.37
8	Barh Stage II	Thermal	2,430.31	957.26	775.27	1,732.52	7.13
9	Nabinagar (BRBCL) Unit I – III	Thermal	152.18	48.20	41.82	90.01	5.92
10	Nabinagar (BRBCL) Unit IV	Thermal	50.73	16.07	13.94	30.00	5.92
11	Talcher Stage I	Thermal	1,158.66	147.02	240.88	387.90	3.35
12	KBUNL Stage II	Thermal	593.25	293.67	173.41	467.08	7.87
13	NPGCL Unit I	Thermal	1,135.21	283.99	314.91	598.90	5.28
14	NPGCL Unit II	Thermal	1,135.21	283.99	314.91	598.90	5.28
15	NPGCL Unit III	Thermal	1,135.21	283.99	314.91	598.90	5.28
16	North Karanpura Unit I	Thermal	465.36	135.00	103.31	238.30	5.12
17	North Karanpura Unit II	Thermal	375.88	101.56	83.45	185.00	4.92
18	Darlipali STPS Unit I	Thermal	350.03	49.70	42.70	92.40	2.64
19	Darlipali STPS Unit II	Thermal	350.03	49.70	42.70	92.40	2.64
20	Chuka	Hydro	232.09	-	55.70	55.70	2.40
21	Rangit	Hydro	49.31	12.81	9.37	22.18	4.50
22	Tala	Hydro	610.71	-	131.91	131.91	2.16
23	Teesta	Hydro	254.58	38.06	29.53	67.59	2.65
24	Mangdechu	Hydro	530.64	-	222.34	222.34	4.19
II	**Stations with injection at STU**		**1,053.59**	**588.60**	**282.13**	**870.73**	**8.26**
1	BSPHC	Hydro	39.07	-	9.73	9.73	2.49
2	BTPS Stage II Unit I	Thermal	507.26	294.30	136.20	430.50	8.49
3	BTPS Stage II Unit II	Thermal	507.26	294.30	136.20	430.50	8.49

SI.	Particulars	Source	Units Considered (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs	Ave Cost Rs.
III	**IPPs**		**1,368.67**	**439.30**	**157.51**	**596.81**	**4.36**
1	GMR	Thermal	527.55	188.14	63.31	251.44	4.77
2	JITPL	Thermal	841.13	251.16	94.21	345.37	4.11
IV	**Renewables**		**3,265.73**	**-**	**992.90**	**992.90**	**3.04**
1	M/s Sunmark Energy Projects Limited (Formerly MBCEL)	Solar	8.95		6.28	6.28	7.02
2	M/s Response renewable Energy Ltd, Kolkata.	Solar	8.95		6.28	6.28	7.02
3	M/s Avantika Contractors Ltd., Hyderabad	Solar	4.47		3.44	3.44	7.69
4	M/s Glatt Solutions Pvt. Ltd, Kolkata.	Solar	2.68		1.88	1.88	7.01
5	Alfa Infraprop Pvt. Ltd.	Solar	17.89		14.08	14.08	7.87
6	Udipta Energy & Equipment Pvt. Ltd.	Solar	4.47		3.57	3.57	7.97
7	Azure Power India Pvt. Ltd.	Solar	8.95		7.52	7.52	8.40
8	Welspun Renewables Project – I	Solar	8.95		7.78	7.78	8.70
9	Welspun Renewables Project – II	Solar	13.42		11.60	11.60	8.64
10	Welspun Renewables Project – III	Solar	13.42		11.49	11.49	8.56
11	Acme Cleantech Project (Nalanda)	Solar	13.42		11.72	11.72	8.73
12	Acme Cleantech Project (Magadh)	Solar	8.95		7.81	7.81	8.73
13	Solar Energy Corporation of India Ltd., Government of India	Solar	8.90		5.28	5.28	5.93
14	SECI Phase-II Solar	Solar	179.37		45.02	45.02	2.51
15	SECI Phase-III (Renew Sunwaves)	Solar	365.09		91.64	91.64	2.51
16	NTPC ISTS Solar	Solar	337.55		90.13	90.13	2.67
17	GRT Jewellars (SECI - V)	Solar	154.23		38.56	38.56	2.50
18	Wind ISTS Scheme Tranche I (PTC) (Greeen Infra, Inox, Mytrah & Ostro)	Wind	253.00		80.45	80.45	3.18
19	Wind ISTS Scheme Tranche II (SECI) (Orange)	Wind	126.50		34.28	34.28	2.71
20	SECI Green Infra	Solar	126.50		31.75	31.75	2.51
21	Alfanar	Wind	63.25		15.94	15.94	2.52

SI.	Particulars	Source	Units Considered (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs	Ave Cost Rs.
22	Betam	Wind	82.01		20.67	20.67	2.52
23	Adani Green (SECI -V)	Solar	189.90		52.41	52.41	2.76
24	Ecoren Energy (SECI - V)	Solar	94.91		26.29	26.29	2.77
25	Ostro Kannad	Wind	444.46		97.34	97.34	2.19
26	Morjar Windfarm	Wind	66.57		14.58	14.58	2.19
27	SEB Renewables (SECI Phase-V Solar)	Solar	364.78		99.22	99.22	2.72
28	BREDA Floating Solar Project	Solar	1.79		0.74	0.74	4.15
29	BREDA Solar Project	Solar	7.67		2.39	2.39	3.11
30	SECI Hybrid Project	Solar	23.63		9.50	9.50	4.02
31	New Swadeshi Sugar Mill, Narkataganj	Other RE	21.90		11.10	11.10	5.07
32	Hasanpur Sugar Mill, Dalsinghsarai	Other RE	31.76		19.75	19.75	6.22
33	Bharat Sugar Mills, Sidhwalia, Gopalganj	Other RE	32.85		16.49	16.49	5.02
34	Hari Nagar Sugar Mills, Hari Nagar, West Champaran	Other RE	31.76		16.13	16.13	5.08
35	HPCL Biofuels Ltd., Sugauli, East Champaran	Other RE	43.80		22.21	22.21	5.07
36	HPCL Biofuels Ltd., Lauria, West Champaran	Other RE	43.80		22.25	22.25	5.08
37	Riga Sugar Company Ltd.	Other RE	6.57		4.11	4.11	6.25
38	Siddhashram Rice Mill Cluster Pvt ltd	Other RE	3.19		2.30	2.30	7.23
39	Bihar Distillers & Bottlers Pvt ltd	Other RE	29.95		19.05	19.05	6.36
40	Tirupati Sugar	Other RE	15.54		9.88	9.88	6.36
V	**Others**				**-**		
1	PTC(IEX)	ST	96.83			50.35	
	Grand Total		**20,747.74**	**4,654.75**	**5,763.79**	**10,418.54**	**5.02**

Annexure 17: SBPDCL - Power Purchase Costs for FY 2024-25 as computed by Commission

Sl.	Particulars	Source	Units (MU)	Fixed Cost (Rs.Crs)	Energy Cost (Rs/Crs)	Total Cost (Rs. Crs)	Ave.Tariff (Rs. /Kwh)
I	Stations with injection at CTU		16641.69	3,372.62	4022.39	7395.02	4.44
1	FSTPP III	Thermal	217.73	51.13	62.71	113.84	5.23
2	KHSTPP II	Thermal	274.83	25.82	62.66	88.48	3.22
3	Barh Stage I Unit I	Thermal	1257.8	201.23	319.48	520.71	4.14
4	Barh Stage I Unit II	Thermal	1112.41	201.23	282.55	483.78	4.35
5	Barh Stage I Unit III	Thermal	691.79	201.23	175.71	376.95	5.45
6	Barh Stage II	Thermal	2423.67	705.01	712.56	1417.56	5.85
7	Nabinagar (BRBCL) Unit I – III	Thermal	151.76	51.44	45.07	96.51	6.36
8	Nabinagar (BRBCL) Unit IV	Thermal	50.59	17.15	15.02	32.17	6.36
9	Korba	Thermal					
10	Talcher Stage I	Thermal					
11	KBUNL Stage II	Thermal	591.63	214.73	159.74	374.47	6.33
12	NPGCL Unit I	Thermal	2058.37	416.93	456.96	873.88	4.25
13	NPGCL Unit II	Thermal	1903.7	385.6	422.62	808.22	4.25
14	NPGCL Unit III	Thermal	1903.7	385.6	422.62	808.22	4.25
15	North Karanpura Unit I	Thermal	843.79	170.91	187.32	358.23	4.25
16	North Karanpura Unit II	Thermal	843.79	170.91	187.32	358.23	4.25
17	Darlipali STPS Unit I	Thermal	349.07	70.19	33.86	104.05	2.98
18	Darlipali STPS Unit II	Thermal	294.33	59.18	28.55	87.73	2.98
19	Chuka	Hydro	231.45	-	55.55	55.55	2.4
20	Rangit	Hydro	49.17	11.57	9.34	20.91	4.25
21	Tala	Hydro	609.04	-	131.55	131.55	2.16
22	Teesta	Hydro	253.88	32.79	29.45	62.24	2.45
23	Mangdechu	Hydro	529.19	-	221.73	221.73	4.19
II	Stations with injection at STU		1495.87	407.38	429.21	836.59	5.59
1	BSPHC	Hydro	38.96	-	9.7	9.7	2.49
2	KBUNL Stage I	Thermal					
3	BTPS Stage I Unit I	Thermal	222.58	16.04	79.24	95.28	4.28

Sl.	Particulars	Source	Units (MU)	Fixed Cost (Rs.Crs)	Energy Cost (Rs/Crs)	Total Cost (Rs. Crs)	Ave.Tariff (Rs. /Kwh)
4	BTPS Stage I Unit II	Thermal	222.58	16.04	79.24	95.28	4.28
5	BTPS Stage II Unit I	Thermal	505.87	187.65	130.51	318.16	6.29
6	BTPS Stage II Unit II	Thermal	505.87	187.65	130.51	318.16	6.29
III	IPPs		1795.39	394.33	207.9	602.23	3.35
1	GMR	Thermal	956.56	162.86	114.79	277.65	2.9
2	JITPL	Thermal	838.83	231.47	93.11	324.58	3.87
IV	Renewables		3769.15		1180.89	1180.89	3.13
1	M/s Sunmark Energy Projects Limited (Formerly MBCEL)	Solar	8.9	-	5.05	5.05	5.67
2	M/s Response renewable Energy Ltd, Kolkata.	Solar	8.9	-	5.05	5.05	5.67
3	M/s Avantika Contractors Ltd., Hyderabad	Solar	4.45	-	3.42	3.42	7.69
4	M/s Glatt Solutions Pvt. Ltd, Kolkata.	Solar	2.67	-	1.51	1.51	5.67
5	Alfa Infraprop Pvt. Ltd.	Solar	17.8	-	14.01	14.01	7.87
6	Udipta Energy & Equipment Pvt. Ltd.	Solar	4.45	-	3.55	3.55	7.98
7	Azure Power India Pvt. Ltd.	Solar	8.9	-	7.47	7.47	8.39
8	Welspun Renewables Project – I	Solar	8.9	-	7.74	7.74	8.7
9	Welspun Renewables Project – II	Solar	13.35	-	11.53	11.53	8.64
10	Welspun Renewables Project – III	Solar	13.35	-	11.43	11.43	8.56
11	Acme Cleantech Project (Nalanda)	Solar	13.35	-	11.65	11.65	8.73
12	Acme Cleantech Project (Magadh)	Solar	8.9	-	7.77	7.77	8.73
13	Solar Energy Corporation of India Ltd., Government of India	Solar	8.85	-	4.87	4.87	5.5
14	SECI Phase-II	Solar	178.38	-	44.77	44.77	2.51
15	SECI Phase-III	Solar	363.11	-	95.13	95.13	2.62
16	NTPC ISTS Solar	Solar	335.78	-	89.65	89.65	2.67
17	Wind ISTS Scheme Tranche I (PTC) (Greeen Infra, Inox, Mytrah&Ostro)	Wind	251.65	-	88.83	88.83	3.53
18	Wind ISTS Scheme Tranche II (SECI) (Orange)	Wind	125.82	-	34.1	34.1	2.71
19	SECI Green Infra	Solar	125.82	-	31.58	31.58	2.51

Sl.	Particulars	Source	Units (MU)	Fixed Cost (Rs.Crs)	Energy Cost (Rs/Crs)	Total Cost (Rs. Crs)	Ave.Tariff (Rs. /Kwh)
20	Torrent Power	Solar	87.4	-	23.68	23.68	2.71
21	Adani Green	Solar	75.49	-	20.53	20.53	2.72
22	Alfanar	Wind	62.91	-	15.85	15.85	2.52
23	Betam	Wind	81.57	-	20.56	20.56	2.52
24	Adani Green (V)	Solar	188.85	-	53.45	53.45	2.83
25	Boreas Renewable	Solar	293.73	-	83.12	83.12	2.83
26	OstroKannad	Wind	441.98	-	127.73	127.73	2.89
27	Morjar Windfarm	Wind	66.2	-	19.13	19.13	2.89
28	SECI Phase-V	Solar	527.78	-	141.97	141.97	2.69
29	BREDA Floating Solar Project	Solar	1.78	-	0.74	0.74	4.16
30	BREDA Solar Project	Solar	178.41	-	55.48	55.48	3.11
31	New Swadeshi Sugar Mill, Narkataganj	Other RE	21.78	-	11.07	11.07	5.08
32	Hasanpur Sugar Mill, Dalsinghsarai	Other RE	31.59	-	19.49	19.49	6.17
33	Bharat Sugar Mills, Sidhwalia, Gopalganj	Other RE	32.68	-	16.5	16.5	5.05
34	Hari Nagar Sugar Mills, Hari Nagar, West Champaran	Other RE	31.59	-	17.59	17.59	5.57
35	HPCL Biofuels Ltd., Sugauli, East Champaran	Other RE	43.57	-	16.16	16.16	3.71
36	HPCL Biofuels Ltd., Lauria, West Champaran	Other RE	43.57	-	23.79	23.79	5.46
37	Riga Sugar Company Ltd.	Other RE	6.54	-	4.08	4.08	6.25
38	Siddhashram Rice Mill Cluster Pvt ltd	Other RE	3.17	-	2.02	2.02	6.36
39	Bihar Distillers & Bottlers Pvt ltd	Other RE	29.78	-	18.94	18.94	6.36
40	Tirupati Sugar	Other RE	15.46	-	9.86	9.86	6.38
	Grand Total		**23702.11**	**4,174.33**	**5840.39**	**10014.72**	**4.23**

Annexure 18: ARR and ACOS approved for FY 2023-24

SI.	Particulars	Approved for NBPDCL	Approved for SBPDCL	Total
1	Purchase of power	8,981.20	10,418.54	19,399.74
2	PGCIL & Other transmission charges	890.11	1,044.91	1,935.02

SI.	Particulars	Approved for NBPDCL	Approved for SBPDCL	Total
3	BSPTCL transmission charges	541.25	635.37	1,176.62
4	BGCL transmission charges	100.91	118.47	219.38
5	SLDC charges	6.15	7.22	13.37
6	RECs Purchases			-
7	O & M Expenses (A+B+C+D)	990.00	1,166.48	2,156.49
A	Employee expenses	481.29	710.44	1,191.73
B	R&M expenses	264.65	274.21	538.86
C	A&G expenses	218.77	155.25	374.03
D	Holding company expenses	25.28	26.59	51.87
8	Depreciation	362.02	364.91	726.93
9	Interest on loan	546.77	444.17	990.94
10	Other finance charges	57.16	70.79	127.95
11	Return on equity	412.89	378.74	791.63
12	Interest on SD	23.29	40.88	64.18
13	Contingency Reserve			-
14	Interest on working capital	-	-	-
15	Less: Non-tariff income	(1,170.01)	(758.44)	(1,928.44)
16	ARR for the year	11,741.75	13,932.05	25,673.80
17	Energy Sales (excluding inter-state sales)	14293.48	16654.1	30,947.58
18	**ACOS**	**8.21**	**8.37**	**8.30**

Annexure 19: Average billing rate as a percentage of average Cost of supply

Sl.	Category	FY 2022-23 (with existing tariff)			FY 2023-24 (revised tariff)		
		ABR (Rs./kWh)	ACOS (Rs./kWh)	% of cost of supply	ABR (Rs./kWh)	ACOS (Rs./kWh)	% of cost of supply
1	Kutir Jyoti	6.32	7.22	0.88	8.00	8.30	0.96
2	Domestic-I	6.48	7.22	0.9	8.30	8.30	1.00
3	Domestic-II	7.22	7.22	1	9.44	8.30	1.14

Sl.	Category	FY 2022-23 (with existing tariff)			FY 2023-24 (revised tariff)		
		ABR (Rs./kWh)	ACOS (Rs./kWh)	% of cost of supply	ABR (Rs./kWh)	ACOS (Rs./kWh)	% of cost of supply
4	DS-III	7.33	7.22	1.02	10.34	8.30	1.25
5	NDS-I	7.15	7.22	0.99	8.83	8.30	1.06
6	NDS-II	9.44	7.22	1.31	12.36	8.30	1.49
7	SS (Metered)	7.76	7.22	1.07	9.69	8.30	1.17
8	SS (Unmetered)	16.31	7.22	2.26	23.91	8.30	2.88
9	IAS-I (Metered)	5.98	7.22	0.83	7.71	8.30	0.93
10	IAS-I (Unmetered)	8.01	7.22	1.11	16.97	8.30	2.04
11	IAS-II	8.98	7.22	1.24	11.91	8.30	1.44
12	Public Water Works	10.83	7.22	1.5	14.44	8.30	1.74
13	Har Ghar Nal	7.35	7.22	1.02	8.94	8.30	1.08
14	LTIS -I	10.33	7.22	1.43	15.41	8.30	1.86
15	LTIS -II	11.5	7.22	1.59	14.77	8.30	1.78
16	LT EVCS	7.94	7.22	1.1	9.86	8.30	1.19
17	HTS – I	9.82	7.22	1.36	13.06	8.30	1.57
18	HTS – II	9.32	7.22	1.29	12.55	8.30	1.51
19	HTS – III	9.05	7.22	1.25	11.53	8.30	1.39
20	HTS-IV	0.00	7.22	0.00	0.00	8.30	0.00
21	HTSS	6.77	7.22	0.94	8.16	8.30	0.98
22	HTIS (Oxygen manu.)	7.77	7.22	1.08	24.09	8.30	2.90
23	Railway	10.89	7.22	1.51	12.79	8.30	1.54
24	HT EV CS	7.17	7.22	0.99	9.77	8.30	1.18

Annexure 20:Consumer category-wise average ABR for Bihar for FY 2023-24

Particulars	NBPDCL		SBPDCL		Average ABR
	Revenue	Energy sales	Revenue	Energy sales	
Domestic	8213.37	9690.91	8249.63	9474.32	8.59

Particulars	NBPDCL Revenue	NBPDCL Energy sales	SBPDCL Revenue	SBPDCL Energy sales	Average ABR
Commercial	2087.26	1887.62	2115.28	1833.4	11.29
Agriculture	510.2	508.59	1588.65	1532.63	10.28
Industrial	2120.08	1639.39	3687.39	3007.17	12.50

NBPDCL

Category	Approved for FY 2023-24 Consumers	Connected Load (KW)	Sales (MU)	Fixed charge (Crores)	Energy Charge (crore)	Total Revenue (crores)	ABR
Domestic	10915513	9320550	9690.91	629.86	7583.51	8213.37	8.48
Kutir Jyoti	4386824	1096706	2358.09	105.28	1785.1	1890.38	8.02
Metered 0-50	43,86,824	1096706	2358.09	105.28	1785.1	1890.38	8.02
DS I Rural	5129603	5518375	4868.2	264.88	3799.18	4064.06	8.35
Metered (Now Demand Based)	5129603	5518375	4868.2	264.88	3799.18	4064.06	8.35
First 50 Units	2912963	3133736	2764.52	150.42	2092.77	2243.19	8.11
51-100 Units	1163312	1251479	1104.03	60.07	895.54	955.61	8.66
101-200 Units	1053328	1133160	999.65	54.39	810.87	865.26	8.66
DS II Demand Based	1399001	2705041	2464.23	259.68	1998.87	2258.56	9.17
First 100 Units	905428	1750691	1594.84	168.07	1207.31	1375.38	8.62
101-200 Units	264407	511245	465.73	49.08	424.04	473.12	10.16
201-300 Units	229166	443105	403.66	42.54	367.52	410.06	10.16
DS III	85	428	0.39	0.01	0.36	0.37	9.54
Non_Domestic Service	814545	1830095	1887.62	482.93	1604.33	2087.26	11.06
NDS I – Metered Now Demand Based	432356	610555	539.96	43.96	437.9	481.86	8.92
First 100 Units	257536	363681	321.63	26.19	255.45	281.64	8.76
101-200 Units	55753	78732	69.63	5.67	58.19	63.86	9.17
Above 200 Units	119067	168142	148.7	12.11	124.26	136.37	9.17
NDS II – Demand Based	382189	1219540	1347.66	438.97	1166.43	1605.4	11.91

Category	Approved for FY 2023-24 Consumers	Connected Load (KW)	Sales (MU)	Fixed charge (Crores)	Energy Charge (crore)	Total Revenue (crores)	ABR
Contract Demand <0.5 kW	548	544	1.93	0.13	1.52	1.65	8.56
Contract Demand >0.5 kW	381641	1218996	1345.73	438.84	1164.91	1603.74	11.92
First 100 Units	134832	430666	475.44	155.04	374.66	529.7	11.14
101-200 Units	29882	95445	105.37	34.36	95.68	130.04	12.34
Above 200 Units	216927	692885	764.92	249.44	694.56	944	12.34
Street Light Services	2256	26369	74.44	190.17	10.29	200.46	26.93
SS Metered	553	5310	11.21	0.64	10.29	10.93	9.75
SS Unmetered	1703	21059	63.23	189.53	0	189.53	29.97
Irrigation & Allied Services	165399	442438	508.59	149.22	360.98	510.2	10.03
IAS I	158638	362037	404.93	95.62	276.65	372.26	9.19
Unmetered	4815	18591	3.27	40.37	0	40.37	123.46
Metered	153823	343446	401.66	55.25	276.65	331.89	8.26
IAS II	6761	80401	103.66	53.6	84.33	137.93	13.31
Metered (Now Demand Based)	6761	80401	103.66	53.6	84.33	137.93	13.31
Public Service Connections	61193	173131	410.86	49.35	356.14	405.49	9.87
Public Water Works	2048	31654	54.86	26.59	60.14	86.73	15.81
Har Ghar Nal	59145	141477	356	22.76	296	318.76	8.95
Low Tension Industrial Services	80802	810406	632.74	320.86	558.39	879.24	13.9
LTIS I (0-19 kW)	79120	709767	511.66	272.55	451.53	724.08	14.15
LTIS II (>19 kW -74 kW)	1682	100639	121.08	48.31	106.85	155.16	12.81
LT Electric Vehicle Charging Station	3	173	0.09	0	0.09	0.09	9.86
High Tension (General)	1484	463922	1006.65	346.43	894.4	1240.84	12.33
HTS I - 11 kV	1410	305012	646.64	223.68	584.03	807.7	12.49
HTS II - 33 kV	68	102992	265.37	75.53	237.85	313.37	11.81
HTS III -132 kV	3	45543	58.72	33.4	52.22	85.62	14.58
HTS IV - 220 kV	0	0	0	0	0	0	

Category	Approved for FY 2023-24 Consumers	Connected Load (KW)	Sales (MU)	Fixed charge (Crores)	Energy Charge (crore)	Total Revenue (crores)	ABR
HTSS	3	10375	35.92	13.83	20.31	34.14	9.5
Railway Traction Services	5	42207	81.2	30.39	75.02	105.41	12.98
HT Electric Veh. Charging Stations.	3	636	0.38	0	0.34	0.34	8.89
Nepal	1	0	458.95	0	352.93	352.93	7.69
Total	12041203	13109927	14293	2199.21	11796.42	13995.63	9.79

SBPDCL

Category	Approved for FY 2023-24 Consumers	Connected Load (KW)	Sales (MU)	Fixed Charges (Crores)	Energy Charges (Crores)	Total Revenue (Crores)	ABR
Domestic	6000429	8534863	9474.32	654.04	7595.59	8249.63	8.71
Kutir Jyoti	1585324	396331	945.35	38.05	715.64	753.69	7.97
Metered 0-50	15,85,324	396331	945.35	38.05	715.64	753.69	7.97
DS I Rural	2897668	3443829	5305.86	165.3	4219.98	4385.28	8.26
Metered (Now Demand Based)	2897668	3443829	5305.86	165.3	4219.98	4385.28	8.26
First 50 Units	8,46,260	1005765	1549.57	48.28	1173.04	1221.32	7.88
51-100 Units	11,79,515	1401834	2159.78	67.29	1751.92	1819.21	8.42
101-200 Units	8,71,893	1036230	1596.51	49.74	1295.02	1344.76	8.42
DS II Demand Based	1517239	4694217	3222.74	450.64	2659.63	3110.28	9.65
First 100 Units	8,42,402	2606324	1789.33	250.21	1354.54	1604.75	8.97
101-200 Units	5,19,264	1606562	1102.96	154.23	1004.22	1158.45	10.5
201-300 Units	1,55,573	481331	330.45	46.21	300.87	347.08	10.5
DS III	198	486	0.37	0.05	0.34	0.39	0.05
Non_Domestic Service	619450	1915086	1833.4	565.39	1549.88	2115.28	11.54
NDS I -Metered Now Demand Based	243128	430390	581.43	30.99	477.22	508.2	8.74
First 100 Units	87499	154893	209.25	11.15	166.19	177.35	8.48
101-200 Units	85890	152044	205.4	10.95	171.65	182.59	8.89

Category	Approved for FY 2023-24 Consumers	Connected Load (KW)	Sales (MU)	Fixed Charges (Crores)	Energy Charges (Crores)	Total Revenue (Crores)	ABR
Above 200 Units	69739	123453	166.78	8.89	139.37	148.26	8.89
NDS II -Demand Based	376322	1484696	1251.97	534.41	1072.67	1607.07	12.84
Contract Demand <0.5 kW	8994	6229	6.17	2.16	4.86	7.02	11.38
Contract Demand >0.5 kW	3,67,328	1478467	1245.8	532.25	1067.81	1600.05	12.84
First 100 Units	1,55,818	627159	528.46	225.78	416.44	642.22	12.15
101-200 Units	44464	178962	150.8	64.43	136.93	201.36	13.35
Above 200 Units	1,67,046	672346	566.54	242.04	514.43	756.48	13.35
Street Light Services	2417	47287	161.35	212.26	53.02	265.28	16.44
SS Metered	1087	24023	57.74	2.88	53.02	55.91	9.68
SS Unmetered	1330	23264	103.61	209.38	0	209.38	20.21
Irrigation & Allied Services	301330	737416	1532.63	827.73	760.92	1588.65	10.37
IAS I	296555	679497	1392.29	789.12	646.75	1435.86	10.31
Unmetered	1,37,821	338094	453.28	734.2	0	734.2	16.2
Metered	1,58,734	341403	939.01	54.92	646.75	701.67	7.47
IAS II	4775	57919	140.34	38.61	114.17	152.79	10.89
Metered (Now Demand Based)	4775	57919	140.34	38.61	114.17	152.79	10.89
Public Service Connections	43898	197666	523.82	68.69	476.03	544.72	10.4
Public Water Works	3365	54325	152.92	45.63	167.63	213.27	13.95
Har Ghar Nal	40533	143341	370.9	23.06	308.39	331.45	8.94
Low Tension Industrial Services	73042	941260	477.36	389.44	421.26	810.71	16.98
LTIS I (0-19 kW)	68282	649593	281.61	249.44	248.52	497.96	17.68
LTIS II (>19 kW - 74 kW)	4760	291667	195.75	140	172.75	312.75	15.98
LT Electric Vehicle Charging Station	5	259	0.12	0	0.12	0.12	9.86
High Tension (General)	2238	1063087	2529.81	866.47	2010.22	2876.68	11.37
HTS I - 11 kV	2035	497152	813.04	364.58	734.32	1098.89	13.52
HTS II - 33 kV	185	347434	655.18	254.78	587.22	842.01	12.85
HTS III -132 kV	5	73721	273.16	54.06	242.94	297.01	10.87

Category	Approved for FY 2023-24 Consumers	Connected Load (KW)	Sales (MU)	Fixed Charges (Crores)	Energy Charges (Crores)	Total Revenue (Crores)	ABR
HTSS	13	144780	788.43	193.04	445.73	638.77	8.1
HT Industrial Services	34	7017	5.23	9.36	3.25	12.6	24.09
HTIS (Oxygen Manufacturers) 11 kV	34	7017	5.23	9.36	3.25	12.6	24.09
Railway Traction Services	4	54833	115.72	39.48	106.91	146.39	12.65
HT Electric Vehicle Charging Stations.	3	634	0.34	0	0.3	0.3	8.89
Total	**7042850**	**13499408**	**16654.1**	**3632.86**	**12977.5**	**16610.36**	**9.97**

Annexure 21: Headroom in Operating Cost (Supply) - Variation in past Trued-Up Years

FY 2019-20

All figures in Rs. Cr. unless specified

Particular	Supply Share	MYT		Tariff Order		True-up Filed		Trued-up approved	
		Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share
Employee cost	40%	789	316	789	316	957	383	874	350
R&M Expenses	10%	415	42	415	42	295	29	339	34
A&G Expenses	50%	270	135	270	135	322	161	261	130
Holding Co. exp.	40%	22	9	22	9	44	18	44	18
Depreciation	10%	421	42	421	42	437	44	347	35
Interest on loans	10%	780	78	780	78	477	48	488	49
Other finance ch.	90%	81	73	81	73	93	83	93	83
Return on Equity	10%	803	80	803	80	424	42	404	40

Particular	Supply Share	MYT		Tariff Order		True-up Filed		Trued-up approved	
		Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share
Interest on SD	100%	67	67	67	67	24	24	24	24
Interest on WC	90%	47	42	47	42	35	31	30	27
Cont. Reserve	0%	120	0	0	0	0	0	0	0
Less: NTI	0%	684	0	684	0	907	0	1,138	0
Total		3,012	884	3,012	884	2,199	863	1,765	789
Energy Sales	MUs		27,513				22,674		22,553
Operating Cost (Supply)	Rs./kwh		0.32				0.38		0.35

FY 2020-21

Particular	Supply Share	MYT		Tariff Order		True-up Filed		Trued-up approved	
		Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share
Employee cost	40%	933	373	842	337	946	378	940	376
R&M Expenses	10%	528	53	405	40	407	41	447	45
A&G Expenses	50%	297	148	288	144	277	138	277	138
Holding Co. exp.	40%	22	9	39	16	32	13	32	13

Particular	Supply Share	MYT		Tariff Order		True-up Filed		Trued-up approved	
		Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share
Depreciation	10%	539	54	386	39	610	61	459	46
Interest on loans	10%	1,007	101	567	57	660	66	649	65
Other finance ch.	90%	89	80	119	107	92	83	92	83
Return on Equity	10%	1,034	103	460	46	524	52	503	50
Interest on SD	100%	75	75	58	58	19	19	19	19
Interest on WC	90%	70	63	46	41	22	19	19	17
Cont. Reserve	0%	157	0	0	0	0	0	0	0
Less: NTI	0%	704	0	813	0	695	0	837	0
Total		3,890	1,060	2,396	885	2,893	871	2,601	852
Energy Sales	MUs		30,846				24,342		24,208
Operating Cost (Supply)	Rs./kwh		0.34				0.36		0.35

FY 2021-22

Particular	Supply Share	MYT		Tariff Order		True-up Filed		Trued-up approved	
		Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share
Employee cost	40%	1,104	442	985	394	1,076	431	1,053	421
R&M Expenses	10%	599	60	467	47	507	51	545	55
A&G Expenses	50%	326	163	305	153	351	175	293	146
Holding Co. exp.	40%	22	9	49	20	46	19	46	19
Depreciation	10%	610	61	473	47	606	61	541	54
Interest on loans	10%	1,109	111	618	62	861	86	798	80
Other finance ch.	90%	98	88	124	111	185	167	106	95
Return on Equity	10%	1,169	117	516	52	658	66	600	60
Interest on SD	100%	84	84	51	51	20	20	20	20
Interest on WC	90%	82	74	37	34	77	70	0	0
Cont. Reserve	0%	180	0	0	0	0	0	0	0
Less: NTI	0%	782	0	615	0	997	0	936	0
Total		4,422	1,209	3,009	969	3,390	1,143	3,065	949
Energy Sales	MUs		34,567				31,374		26,525
Operating Cost (Supply)	Rs./kwh		0.35				0.364		0.358

Haryana

Annexure 22:Approved Power Purchase Quantum and cost for FY 2023-24

Sl.	Particulars	Source	Quantum (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs
	NTPC					
1	Singrauli STPS	Thermal	1300.00	1004.00	1914.00	2917.00
2	Rihand STPS I	Thermal	441.00	417.00	645.00	1062.00
3	Rihand II TPS	Thermal	360.00	295.00	545.00	840.00
4	Rihand III TPS	Thermal	354.00	502.00	531.00	1033.00
5	Unchhahar TPS I	Thermal	51.00	113.00	222.00	335.00
6	Unchhahar TPS II	Thermal	100.00	163.00	430.00	594.00
7	Unchhahar TPS III	Thermal	46.00	73.00	199.00	272.00
8	Unchhahar TPS IV	Thermal	182.00	501.00	746.00	1247.00
9	Faridabad CCPP	Thermal	0.00	0.00	0.00	0.00
10	Farakka STPS	Thermal	38.00	80.00	151.00	231.00
11	Kahalgaon I STPS	Thermal	109.00	170.00	406.00	576.00
12	Kahalgaon II STPS	Thermal	331.00	487.00	1186.00	1672.00
13	Kol Dam HPS	Hydro	310.00	739.00	760.00	1499.00
	NHPC					
13	Salal I HPS	Hydro	452.00	723.00	479.00	1202.00
14	Bairasiul HPS	Hydro	146.00	178.00	164.00	341.00
15	Tanakpur HPS	Hydro	28.00	80.00	46.00	126.00
16	Chamera I HPS	Hydro	337.00	410.00	383.00	793.00
17	Chamera II HPS	Hydro	87.00	96.00	88.00	183.00
18	Chamera-III HPS	Hydro	80.00	164.00	167.00	331.00
19	Dhauliganga HPS	Hydro	66.00	147.00	81.00	228.00
20	Dulhasti HPS	Hydro	116.00	452.00	295.00	747.00
21	Uri I HPS	Hydro	137.00	214.00	142.00	356.00

Sl.	Particulars	Source	Quantum (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs
22	Uri-II HPS	Hydro	83.00	291.00	196.00	487.00
23	Sewa II HPS	Hydro	28.00	76.00	78.00	154.00
24	Parbati-II HPS	Hydro	177.00	364.00	366.00	731.00
25	Parbati-III HPS	Hydro	58.00	201.00	90.00	291.00
	SJVNL					
26	SJVNL (Nathpa Jhakri) HPS	Hydro	287.00	561.00	340.00	901.00
27	Rampur HPS	Hydro	70.00	295.00	146.00	441.00
	THDC					
28	Tehri (THDC) HPS	Hydro	210.00	447.00	561.00	1008.00
29	Koteshwar HPS	Hydro	48.00	164.00	117.00	281.00
	Nuclear Power Corp. (NPC)					
30	NAPP (Narora) Hry 28 MW	Thermal	197.00	0.00	587.00	587.00
31	RAPP (3-4) Hry 48	Thermal	552.00	9.00	2028.00	2037.00
32	HPGCL	Thermal	17597.21	15497.02	68501.00	83998.00
	Shared Project					
33	BBMB HPS	Hydro	3300.00	2240.00	0.00	2240.00
34	DVC	Thermal				
35	Mejia TPS	Thermal	569.00	1311.00	2009.00	3320.00
36	Koderma TPS	Thermal	569.00	1490.00	2106.00	3596.00
37	Raghunathpur TPS	Thermal	569.00	1200.00	2134.00	3334.00
38	UMPP	Thermal				
39	CGPL Mundra UMPP TPS	Thermal	0.00	0.00	0.00	0.00
40	Sasan UMPP TPS	Thermal	3278.00	573.00	4196.00	4769.00
	Other Long Term Power					
41	PTC Tala, HPS	Hydro	44.00	0.00	99.00	99.00
42	PTC GMR Kamalanga TPS	Thermal	2223.00	3183.00	6491.00	9674.00
43	Baglihar HPS Stage 1 J&K	Hydro	407.00	0.00	1486.00	1486.00

Sl.	Particulars	Source	Quantum (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs
44	J&K PTC	Thermal	271.00	0.00	1025.00	1025.00
45	PTC Lanco Amarkantak TPS	Thermal	1860.00	3000.00	3549.00	6549.00
46	PTC Karchamwangtoo HPS	Thermal	2697.00	3911.00	3830.00	7741.00
47	IGSTPP, Jhajjar (Aravali) TPS	Thermal	3447.00	10622.00	11393.00	22015.00
48	Pragati Power CCPP	Thermal	287.00	1697.00	1880.00	3577.00
49	Adani Power Ltd. Mundra TPS	Thermal	2195.00	2261.00	5422.00	7683.00
50	MGSTPS, CLP, Jhajjar TPS	Thermal	7022.00	5813.00	28775.00	34588.00
51	Hydro (Gati, Dans, Shiga, IA)	Thermal	1287.00	0.00	5102.00	5102.00
52	NEEPCO	Thermal	65.00	0.00	270.00	270.00
53	Subhansari (Unit 1&2)	Thermal	170.00	364.00	350.00	714.00
	RE Power					
53	P&R Gogripur Small Hydro	Hydro	9.71	0.00	38.70	38.70
54	Bhoruka Power Corps. Ltd. Small Hydro	Hydro	29.14	0.00	91.50	91.50
55	Shahbad Sugar Mill	Other RE	40.07	0.00	161.00	161.00
56	Naraingarh Suagar Mill	Other RE	69.56	0.00	442.30	442.30
57	Ch. Devi Lal Sugar Mill	Other RE	4.45	0.00	18.00	18.00
58	Haryana Co. Sugar Mill.	Other RE	26.71	0.00	177.00	177.00
59	Hafed Sugar Mill	Other RE	4.45	0.00	18.00	18.00
60	Puri Oil Mill Small Hydro	Hydro	13.60	0.00	49.90	49.90
61	SDS Solar Pvt Ltd.	Solar	1.66	0.00	9.40	9.40
62	EON	Solar	1.66	0.00	9.40	9.40
63	Chandraleela Solar	Solar	1.33	0.00	7.50	7.50
64	Sukhbir Solar	Solar	1.66	0.00	9.40	9.40
65	Xion Energy	Solar	1.66	0.00	9.40	9.40
66	Siwana Solar Power	Solar	8.30	0.00	47.70	47.70
67	HR Mineral Solar	Solar	1.66	0.00	9.40	9.40

Sl.	Particulars	Source	Quantum (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs
68	Tayal & Co Solar	Solar	1.66	0.00	9.40	9.40
69	VKG Solar Uh	Solar	1.66	0.00	9.40	9.40
70	Utrecht Solar Pvt. Ltd.	Solar	1.66	0.00	9.20	9.20
71	Subhash Infra Engineers Pvt Ltd.	Solar	1.66	0.00	8.70	8.70
72	JBM Solar	Solar	33.20	0.00	188.60	188.60
73	Balarch Solar	Solar	1.66	0.00	9.40	9.40
74	Greenyana Solar	Solar	33.20	0.00	102.30	102.30
75	Raj Waste Treat Pvt. Ltd	Other RE	3.32	0.00	10.20	10.20
76	Deepan Godara	Other RE	0.42	0.00	1.30	1.30
77	HPGCL-Solar	Solar	16.60	0.00	81.00	81.00
78	Amplus	Solar	83.01	0.00	206.00	206.00
79	Avaada Green	Other RE	83.01	0.00	237.00	237.00
80	Avaada RJHN	Other RE	398.46	0.00	1087.90	1087.90
81	LR Energy	Other RE	33.20	0.00	85.80	85.80
82	SECI Wind-T-II @ 2.71	Wind	338.22	0.00	948.50	948.50
83	SECI Wind-T-III @ 2.51	Wind	887.84	0.00	2306.00	2306.00
84	SECI Wind-Inter @ 2.72	Wind	101.47	0.00	289.50	289.50
85	SECI-Hybrid	Solar	297.64	0.00	850.10	850.10
86	SECI Solar T-1 @ 2.60	Solar	435.81	0.00	1172.50	1172.50
87	SECI Solar T-IV Mega Surya @ 2.61	Solar	146.10	0.00	298.60	298.60
88	SECI Solar @ 5.5	Solar	49.81	0.00	283.50	283.50
89	Star Wire India	Other RE	66.34	0.00	566.60	566.60
90	Gemco Energy Ltd.	Other RE	53.61	0.00	457.80	457.80
91	Oasis Commercial Pvt. Ltd.	Other RE	33.51	0.00	209.60	209.60
92	JBM Environment	Other RE	32.57	0.00	209.80	209.80
93	Sri Jyoti	Other RE	63.66	0.00	552.20	552.20
94	Sukhbir Agro Energy Limited	Other RE	92.51	0.00	449.70	449.70

Sl.	Particulars	Source	Quantum (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs
95	Hind Samachar Ltd.	Other RE	92.51	0.00	430.20	430.20
96	Mor Bio Energy	Other RE	8.26	0.00	57.40	57.40
97	PM Kusum -- Sh. Rajender Kumar	Solar	1.66	0.00	5.20	5.20
98	PM Kusum -- Sh. Mahesh Kumar	Solar	1.66	0.00	5.20	5.20
99	PM Kusum -- Smt. Kulwinder Kaur	Solar	2.19	0.00	6.80	6.80
100	PM Kusum -- Smt. Kaushalya	Solar	1.66	0.00	5.20	5.20
101	PM Kusum -- Sh. Vijaynder Singh Brar	Solar	3.32	0.00	10.30	10.30
102	PM Kusum -- Sh. Satish Kumar Jaglan	Solar	3.32	0.00	10.30	10.30
103	SECI under 3000MW ISTS Solar Scheme	Solar		0.00	0.00	0.00
104	SECI Wind P II - 1000 MW ISTS	Wind	63.14	0.00	180.10	180.10
105	SECI Wind 590 MW (Tranche-V) - 115 MW	Wind	388.96	0.00	1109.80	1109.80
106	SECI Wind 590 MW (Tranche-V) -25 MW	Wind	84.56	0.00	241.30	241.30
107	SECI Wind 590 MW (Tranche-V) -150 MW	Wind	507.34	0.00	1447.50	1447.50
108	SECI Wind 590 MW (Tranche-V) - 115 MW -Alfanar Nefra	Wind	388.96	0.00	1109.80	1109.80
109	SECI Wind 590 MW (Tranche-V) - 175 MW -Alfanar Nefra	Wind	591.89	0.00	1688.80	1688.80
110	SECI Wind 590 MW (Tranche-V) - 300 MW -Alfanar Nefra	Wind	0.00	0.00	0.00	0.00
111	SECI Hybrid (Solar)	Solar	134.57	0.00	383.90	383.90
112	SECI Hybrid (Wind)	Wind	27.58	0.00	74.50	74.50
113	M/s Cleantech Power LLP	Solar	13.40	0.00	114.50	114.50
114	K2P Biomass Gasifier Power Project	Other RE	13.40	0.00	114.50	114.50
115	MS Fathehabad Bio Energy (LLP)	Other RE	62.44	0.00	533.20	533.20
116	M/s Jind Bio Energy (LLP)	Other RE	62.44	0.00	533.20	533.20
117	M/s Karnal Sugar Mill	Other RE	41.29	0.00	192.00	192.00
118	M/s Panipat Co-operative Sugar Mill	Other RE	65.68	0.00	305.50	305.50
119	M/s RSL Distillery Pvt. Ltd.	Hydro	18.92	0.00	161.60	161.60

Sl.	Particulars	Source	Quantum (MU)	Fixed Charges Rs. Crs	Energy Cost Rs. Crs	Total Cost Rs. Crs
120	Short Term Power #	ST	5905.19	51.50	37038.99	37,090.49
	TOTAL		**66,631.39**	**62,629.02**	**220,204.21**	**282,833.23**

Annexure 23: Aggregate Revenue Requirement for FY 2023-24 (Rs Cr.)

UHBVNL		
SI.	**Particulars**	**FY 2023-24**
1	Total Power Purchase Expense	13,990.30
1.1	Power Purchase Expense	11,931.85
1.2	Interstate transmission Charge	1,013.54
1.3	Intrastate transmission & SLDC	1,044.91
2	Operations and Maintenance Expense	1,816.64
2.1	Employee Expense	1,018.99
2.2	Administration & General Exp.	162.58
2.3	Repair & Maintenance Expense	185.07
2.4	Terminal Liability	450.00
3	Depreciation	462.66
4	Total Interest & Finance Charges	323.37
4.1	Interest on CAPEX loans	105.48
4.2	Interest on Working Capital incl. CC	116.39
4.3	Interest on Consumer Security Deposit	66.59
4.4	Other Interest and Finance charges	34.90
5	Return on Equity Capital	277.67
6	Other Expenses	-
7	Total Expenditure	16,870.63
8	Less: Non-Tariff Income	278.43
9	Net Aggregate Revenue Requirement	16,592.20

DHBVNL		
SI.	**Particulars**	**ARR**
1	Power Purchase Expenses	18,960.86
1.1	Power Purchase Cost	16,351.48
1.2	Transmission Charges	1,388.96
1.3	Transmission Charges & SLDC	1,220.41
2	Operation & Maintenance Expenses	2,209.99
2.1	Employee Expenses (net)	1,271.32
2.2	Administration & General Expenses (net)	144.34
2.3	Repair & Maintenance Expenses	235.33
2.4	Terminal Benefits	550.00
3	Depreciation	452.20
4	Interest & Finance Charges	473.99
4.1	Interest on Long Term Loan	154.59
4.2	Interest on Working Capital	186.95
4.3	Interest on UDAY Bonds	-
4.4	Interest on Consumer Security Deposit	100.06
4.5	Other Interest & Finance Charges	8.40
4.6	Guarantee Fee	24.00
5	Return on Equity Capital	285.13
6	Provision for Bad & Doubtful Debt	-
7	Aggregate Revenue Requirement	22,373.17

UHBVNL		
SI.	Particulars	FY 2023-24

DHBVNL		
SI.	Particulars	ARR
8	Less: Non-Tariff Income	279.22
9	Net Aggregate Revenue Requirement	22,093.95

Annexure 24: Cross-subsidy surcharge for FY 2023-24 (Rs/kWh)

SI.	Particulars	CoS (Rs./kWh)	Tariff (FC + EC) (Rs./kWh)	Cross Subsidy Surcharge (Rs./kWh)	Limited to 20% as per NTP
1	HT Supply	6.22	7.59	1.37	1.24
2	Bulk Supply (other than DS)	6.22	7.38	1.16	1.16
3	LT Supply	6.62	7.63	1.01	1.01

Annexure 25: Headroom in Operating Cost (Supply) - Variation in past Trued-Up Years

FY 2019-20

Particular		Tariff Order	True-up Filed	Trued-up approved
Total ARR	Rs. Cr.	29,472	31,706	30,483
Less: Power Purchase Cost inc trans.	Rs. Cr.	24,736	26,561	26,085
Less: Distribution Wheeling Exp.	Rs. Cr.	2,818	3,031	2,914
Less: Non-tariff income	0%	0	0	0
Total		**1,918**	**2,114**	**1,484**
Energy Sales	MUs	41,786	41,847	41,847
Operating Cost (Supply)	Rs./Unit	0.46	0.51	0.35

FY 2020-21

Particular		Tariff Order	True-up Filed	Trued-up approved
Total ARR	Rs. Cr.	28,365	28,588	27,509
Less: Power Purchase Cost inc trans.	Rs. Cr.	24,053	23,623	23,362
Less: Distribution Wheeling Exp.	Rs. Cr.	2,712	2,733	2,630
Less: Non-tariff income	0%	0	0	0
Total		**1,601**	**2,232**	**1,517**
Energy Sales	MUs	37,177	41,856	41,856
Operating Cost (Supply)	Rs./Unit	0.43	0.53	0.46

FY 2021-22

Particular		Tariff Order	True-up Filed	Trued-up approved
Total ARR	Rs. Cr.	30,516	32,840	32,671
Less: Power Purchase Cost inc trans.	Rs. Cr.	25,367	27,359	27,286
Less: Distribution Wheeling Exp.	Rs. Cr.	2,917	3,140	3,123
Less: Non-tariff income	0%	0	0	0
Total		**2,231**	**2,341**	**2,262**
Energy Sales	MUs	44,143	45,357	45,357
Operating Cost (Supply)	Rs./Unit	0.51	0.52	0.50

Tamil Nadu

Annexure 26: Approved Power Purchase Expenses for FY 2022-23

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores	Cost Rs./kWh
A	**Central Generating Stations**							
1	New Neyveli TS	Thermal	3,527.72	2.24	789.31	714.15	1,503.47	4.26
2	Neyveli TS-II Stage I	Thermal	3,725.59	2.71	1,009.73	211.85	1,221.58	3.28
3	NLC TPS-II Second Expansion	Thermal	-	-	-	-	-	-
4	Neyveli TS-I Expansion	Thermal	1,626.69	2.47	401.61	155.35	556.96	3.42
5	Neyveli Expansion Unit II	Thermal	1,000.06	2.61	261.39	228.99	490.38	4.9
6	NTPL JV with NLC	Thermal	1,851.88	3.26	604.35	362.86	967.2	5.22
7	Ramagundam I&II	Thermal	3,393.13	2.94	998.14	263.12	1,261.26	3.72
8	Ramagundam III	Thermal	856.06	2.89	247.14	78.42	325.57	3.8
9	Simhadri Stage II -Unit III	Thermal	1,230.81	3.04	374.7	231.19	605.89	4.92
10	Simhadri Stage II -Unit IV	Thermal	-	-	-			
11	NTPC_TNEB JV Vallur Unit 1	Thermal	5,294.73	3.53	1,871.65	1,325.97	3,197.62	6.04
12	NTPC_TNEB JV Vallur Unit 2	Thermal	-	-	-		-	
13	Talcher	Thermal	3,531.34	1.86	658.57	266.61	925.18	2.62
14	Madras APS	Thermal	796.33	2.65	210.84		210.84	2.65
15	Kaiga APS	Thermal	1,898.66	3.66	694.78		694.78	3.66
16	Kudankulam	Thermal	8,114.87	4.3	3,489.05		3,489.05	4.3
17	NTPC ER	Thermal	115.32	2.68	30.9	24.13	55.03	4.77
18	Kudgi Unit I	Thermal	914.74	4.13	377.86	383.81	761.66	8.33
19	NTPC Bongaigaun	Thermal	960	3.55	340.8	211.2	552	5.75
20	NTPC/Barh-1	Thermal	502.46	2.78	139.76	28.84	168.6	3.36
21	NTPC/Barh-2	Thermal	593.33	3.17	187.96	45.92	233.88	3.94
22	NTPC/KBUN	Thermal	455.58	2.79	127.29	44.49	171.78	3.77
23	NLC Talabira	Thermal	-	-	-	-	-	-

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores	Cost Rs./kWh
	Total CGS		**40,389.31**	**3.19**	**12,815.84**	**4,576.88**	**17,392.72**	**4.31**
B	**IPPS**							
24	SEPC	Thermal	643.29	6	385.97	160.82	546.79	8.5
25	TAQA (STCMS)	Thermal	1,314.00	3.56	468	245.94	713.94	5.43
26	LANCO Power (Aban co)	Thermal	-	-	-	-	-	
27	PIONEER Power co. (Penna)	Thermal	-	1.55	-	-	-	
C	**Renewables**			**-**				
28	Windmill	Wind	3,332.15	3.12	1,040.40		1,040.40	3.12
29	Co-generation	Other RE	347.07	3.43	119.09	64.51	183.6	5.29
30	Cogeneration new	Other RE	-	-	-	-	-	
31	Biomass	Other RE	2.1	5.33	1.12	0.39	1.51	7.2
32	Captive generation	Others	15.18	2.03	3.09	-	3.09	2.03
33	Solar	Solar	6,977.89	4.48	3,124.55	-	3,124.55	4.48
34	Co-Gen in Co-op Sugar Mills	Other RE	-	-	-	-	-	
35	UI Power	Others	-	15.42	-	-	-	
36	Traders-MTOA	Traders	910.55	4	364.08	24.05	388.13	4.26
37	Traders-LTOA	Traders	11,837.20	2.6	3,075.10	2,591.23	5,666.34	4.79
38	Traders -STOA	Traders	910.55	3.58	325.74	-	325.74	3.58
39	CPP_Traders			-	-	-	-	
40	Power Exchanges	IEX	7,208.70	6.38	4,598.90	-	4,598.90	6.38
41	STOA Charges	IEX				74.85	74.85	
	Total		**73,888.00**		**26,321.89**	**7,738.67**	**34,060.56**	**4.61**

Annexure 27: Approved Power Purchase Expenses for FY 2023-24

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
A	**Central Generating Stations**							
1	New Neyveli TS	Thermal	3,643.50	2.28	831.52	716.15	1,547.68	4.25
2	Neyveli TS-II Stage I	Thermal	3,847.87	2.76	1,063.73	213.85	1,277.58	3.32
3	NLC TPS-II Second Expansion	Thermal	-	-	-	-	-	-
4	Neyveli TS-I Expansion	Thermal	1,647.45	2.52	414.88	157.35	572.23	3.47
5	Neyveli Expansion Unit II	Thermal	1,032.88	2.67	275.37	230.99	506.36	4.9
6	NTPL JV with NLC	Thermal	1,912.67	3.33	636.67	364.86	1,001.52	5.24
7	Ramagundam I&II	Thermal	3,504.50	3.09	1,082.45	265.12	1,347.57	3.85
8	Ramagundam III	Thermal	884.16	3.03	268.02	80.42	348.44	3.94
9	Simhadri Stage II -Unit III	Thermal	1,271.21	3.2	406.35	235.19	641.54	5.05
10	Simhadri Stage II -Unit IV	Thermal	-	-	-			
11	NTPC_TNEB JV Vallur Unit 1	Thermal	5,468.52	3.71	2,029.73	1,327.97	3,357.70	6.14
12	NTPC_TNEB JV Vallur Unit 2	Thermal	-	-	-		-	
13	Talcher	Thermal	3,647.24	1.96	714.2	268.61	982.81	2.69
14	Madras APS	Thermal	822.47	2.78	228.64		228.64	2.78
15	Kaiga APS	Thermal	1,960.97	3.84	753.47		753.47	3.84
16	Kudankulam	Thermal	8,381.22	4.51	3,783.75		3,783.75	4.51
17	NTPC ER	Thermal	119.11	2.81	33.51	26.13	59.64	5.01
18	Kudgi Unit I	Thermal	944.76	4.34	409.77	385.81	795.58	8.42
19	NTPC/Barh-1	Thermal	517.53	2.92	151.15	29.42	180.56	3.49
20	NTPC/Barh-2	Thermal	611.13	3.33	203.28	46.84	250.11	4.09
21	NTPC/KBUN	Thermal	469.25	2.93	137.67	45.38	183.05	3.9
	Total CGS		**40,686.46**	**3.34**	**13,424.15**	**4,394.07**	**17,818.21**	**4.38**
B	IPPS							
22	SEPC	Thermal	643.29	3	192.99	160.82	353.81	5.5
23	TAQA (STCMS)	Thermal	1,317.60	3.74	492.75	247.94	740.68	5.62
24	LANCO Power (Aban co)	Thermal	-	-	-	-	-	

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
25	PIONEER Power co. (Penna)	Thermal	-	1.63	-	-	-	
C	Renewables			-				
26	Windmill	Wind	3,432.12	3.28	1,125.19		1,125.19	3.28
27	Co-generation	Other RE	347.07	3.6	125.05	66.51	191.55	5.52
28	Cogeneration new	Other RE	-	-	-	-	-	
29	Biomass	Other RE	2.1	5.6	1.18	0.39	1.57	7.46
30	Captive generation	Others	15.18	2.14	3.24	-	3.24	2.14
31	Solar	Solar	7,466.34	4.48	3,343.27		3,343.27	4.48
32	UI Power	Others	-	16.19	-	-	-	
33	Traders-MTOA	Traders	885.65	4	354.12	24.05	378.17	4.27
34	Traders-LTOA	Traders	11,513.39	2.6	2,990.99	2,520.35	5,511.34	4.79
35	Traders -STOA	Traders	885.65	3.58	316.83	-	316.83	3.58
36	Power Exchanges	IEX	6,535.17	6.38	4,169.20	-	4,169.20	6.38
37	STOA Charges	IEX				74.85	74.85	
38	**Total**		**73,730.00**		**26,538.95**	**7,488.97**	**34,027.92**	**4.62**

Annexure 28: Approved Power Purchase Expenses for FY 2024-25

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
A	**Central Generating Stations**							
1	New Neyveli TS	Thermal	3,742.55	2.33	871.21	718.15	1,589.37	4.25
2	Neyveli TS-II Stage I	Thermal	3,952.48	2.82	1,114.50	215.85	1,330.35	3.37
3	NLC TPS-II Second Expansion	Thermal	-	-	-	-	-	-
4	Neyveli TS-I Expansion	Thermal	1,642.95	2.57	422.02	159.35	581.37	3.54
5	Neyveli Expansion Unit II	Thermal	1,060.96	2.72	288.51	232.99	521.51	4.92
6	NTPL JV with NLC	Thermal	1,964.66	3.4	667.05	366.86	1,033.91	5.26
7	Ramagundam I&II	Thermal	3,599.78	3.24	1,167.47	267.12	1,434.59	3.99

Sl.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
8	Ramagundam III	Thermal	908.2	3.18	289.07	82.42	371.49	4.09
9	Simhadri Stage II -Unit III	Thermal	1,305.77	3.36	438.27	239.19	677.46	5.19
10	Simhadri Stage II -Unit IV	Thermal	-	-	-			
11	NTPC_TNEB JV Vallur Unit 1	Thermal	5,617.18	3.9	2,189.16	1,329.97	3,519.13	6.26
12	NTPC_TNEB JV Vallur Unit 2	Thermal	-	-	-		-	
13	Talcher	Thermal	3,746.40	2.06	770.29	270.61	1,040.90	2.78
14	Madras APS	Thermal	844.83	2.92	246.6		246.6	2.92
15	Kaiga APS	Thermal	2,014.28	4.03	812.65		812.65	4.03
16	Kudankulam	Thermal	8,609.07	4.74	4,080.94		4,080.94	4.74
17	Kudankulam II	Thermal	-	-	-		-	
18	NTPC ER	Thermal	122.35	2.95	36.14	28.13	64.27	5.25
19	Kudgi Unit I	Thermal	970.45	4.55	441.96	387.81	829.76	8.55
20	NTPC Bongaigaun	Thermal	-	3.8	-	-	-	-
21	NTPC/Barh-1	Thermal	533.06	3.07	163.47	30	193.47	3.63
22	NTPC/Barh-2	Thermal	629.46	3.49	219.84	47.77	267.62	4.25
23	NTPC/KBUN	Thermal	483.33	3.08	148.89	46.29	195.17	4.04
	Total CGS		**41,747.76**		**13,835.85**	**4,298.44**	**18,790.55**	**4.5**
B	IPPS							
24	SEPC	Thermal	643.29	3.15	202.63	160.82	363.46	5.65
25	TAQA (STCMS)	Thermal	1,314.00	3.81	501.23	249.94	751.17	5.72
26	LANCO Power (Aban co)	Thermal	-	-	-	-	-	
27	PIONEER Power co. (Penna)	Thermal	-	1.66	-	-	-	
C	**Renewables**							
28	Windmill	Wind	3,535.08	3.28	1,158.95		1,158.95	3.28
29	Co-generation	Other RE	347.07	3.6	125.05	66.51	191.55	5.52
30	Cogeneration new	Other RE	-	-	-	-	-	
31	Biomass	Other RE	2.1	5.6	1.18	0.39	1.57	7.46

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
32	Captive generation	Others	15.18	2.14	3.24	-	3.24	2.14
33	Solar	Solar	7,988.99	4.48	3,577.30		3,577.30	4.48
34	Traders-MTOA	Traders	924.66	4	369.72	24.05	393.77	4.26
35	Traders-LTOA	Traders	12,020.53	2.6	3,122.73	2,631.37	5,754.10	4.79
36	Traders -STOA	Traders	924.66	3.58	330.79	-	330.79	3.58
37	Power Exchanges	IEX	6,130.70	6.38	3,911.17	-	3,911.17	6.38
38	STOA Charges	IEX				74.85	74.85	
39	**Total**		**75,594.00**		**27,139.83**	**7,506.36**	**35,302.45**	**4.67**

Annexure 29: Approved Power Purchase Expenses for FY 2025-26

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
A	**Central Generating Stations**							
1	New Neyveli TS	Thermal	3,854.83	2.37	915.29	720.15	1,635.45	4.24
2	Neyveli TS-II Stage I	Thermal	4,071.06	2.88	1,170.90	217.85	1,388.74	3.41
3	New Neyveli TS-II	Thermal	2,737.23	2.08	569.34	561.13	1,130.47	4.13
4	Neyveli TS-I Expansion	Thermal	1,642.95	2.62	430.46	161.35	591.81	3.6
5	Neyveli Expansion Unit II	Thermal	1,092.79	2.77	303.11	234.99	538.1	4.92
6	NTPL JV with NLC	Thermal	2,023.60	3.46	700.81	368.86	1,069.66	5.29
7	Ramagundam I&II	Thermal	3,707.77	3.41	1,262.62	269.12	1,531.74	4.13
8	Ramagundam III	Thermal	935.44	3.34	312.63	84.42	397.05	4.24
9	Simhadri Stage II -Unit III	Thermal	1,344.94	3.52	473.99	243.19	717.18	5.33
10	Simhadri Stage II -Unit IV	Thermal	-	-	-			
11	NTPC_TNEB JV Vallur Unit 1	Thermal	5,785.70	4.09	2,367.58	1,331.97	3,699.54	6.39
12	NTPC_TNEB JV Vallur Unit 2	Thermal	-	-	-		-	
13	Talcher	Thermal	3,858.79	2.16	833.07	272.61	1,105.68	2.87
14	Madras APS	Thermal	870.17	3.06	266.7		266.7	3.06

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
15	Kaiga APS	Thermal	2,074.71	4.24	878.88		878.88	4.24
16	Kudankulam	Thermal	8,867.34	4.98	4,413.54		4,413.54	4.98
17	Kudankulam II	Thermal	-	-	-		-	
18	PFBR Kalpakkam	Thermal	-	-	-		-	-
19	NTPC ER	Thermal	126.02	3.1	39.09	30.13	69.22	5.49
20	Kudgi Unit I	Thermal	999.56	4.78	477.98	389.81	867.78	8.68
21	Kudgi Unit II	Thermal	-	-	-	-	-	-
22	Talcher I	Thermal	-	-	-	-	-	-
23	NTPC Kayamkulam	Thermal	-	-	-	-	-	-
24	NTPC Bongaigaun	Thermal	-	3.99	-	-	-	-
25	NTPC/Barh-1	Thermal	549.05	2.78	152.72	30.61	183.32	3.34
26	NTPC/Barh-2	Thermal	648.35	3.17	205.39	48.73	254.11	3.92
27	NTPC/KBUN	Thermal	497.83	2.79	139.1	47.21	186.31	3.74
28	NLC Talabira	Thermal	-	-	-	-	-	-
	Total CGS		**45,688.13**	**-**	**15,913.18**	**5,012.11**	**20,925.29**	**4.58**
B	IPPS			-				
29	SEPC	Thermal	643.29	3.31	212.77	160.82	373.59	5.81
30	TAQA (STCMS)	Thermal	1,314.00	4.01	526.29	249.94	776.23	5.91
31	PIONEER Power co. (Penna)	Thermal	-	1.75	-	-	-	
C	**Renewables**			**-**				
32	Windmill	Wind	3,641.13	3.44	1,253.40		1,253.40	3.44
33	Co-generation	Other RE	347.07	3.78	131.3	66.51	197.8	5.7
34	Cogeneration new	Other RE	-	-	-	-	-	
35	Biomass	Other RE	2.1	5.88	1.24	0.39	1.63	7.74
36	Captive generation	Others	15.18	2.24	3.4	-	3.4	2.24
37	Solar	Solar	8,548.21	4.48	3,827.71		3,827.71	4.48
38	Traders-MTOA	Traders	962.34	4	384.79	24.05	408.84	4.25
39	Traders-LTOA	Traders	12,510.44	2.6	3,250.00	2,738.61	5,988.61	4.79

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
40	Traders -STOA	Traders	962.34	3.58	344.27	-	344.27	3.58
41	Power Exchanges	IEX	4,810.76	6.38	3,069.10	-	3,069.10	6.38
42	STOA Charges	IEX				74.85	74.85	
43	**Total**		**79,445.00**		**28,917.44**	**8,327.28**	**37,244.71**	**4.69**

Annexure 30: Approved Power Purchase Expenses for FY 2026-27

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
A	**Central Generating Stations**							
1	New Neyveli TS	Thermal	3,970.48	2.42	961.61	722.15	1,683.76	4.24
2	Neyveli TS-II Stage I	Thermal	4,193.19	2.93	1,230.14	219.85	1,449.99	3.46
3	New Neyveli TS-II	Thermal	5,420.25	2.12	1,149.96	1,111.15	2,261.11	4.17
4	Neyveli TS-I Expansion	Thermal	1,642.95	2.67	439.07	163.35	602.42	3.67
5	Neyveli Expansion Unit II	Thermal	1,125.57	2.83	318.45	236.99	555.44	4.93
6	NTPL JV with NLC	Thermal	2,084.31	3.53	736.27	370.86	1,107.12	5.31
7	Ramagundam I&II	Thermal	3,819.00	3.58	1,365.52	271.12	1,636.64	4.29
8	Ramagundam III	Thermal	963.51	3.51	338.11	86.42	424.53	4.41
9	Simhadri Stage II -Unit III	Thermal	1,385.29	3.7	512.62	247.19	759.81	5.48
10	NTPC_TNEB JV Vallur Unit 1	Thermal	5,959.27	4.3	2,560.53	1,333.97	3,894.50	6.54
11	Talcher	Thermal	3,974.55	2.27	900.97	274.61	1,175.58	2.96
12	Madras APS	Thermal	896.28	3.22	288.44		288.44	3.22
13	Kaiga APS	Thermal	2,136.95	4.45	950.51		950.51	4.45
14	Kudankulam	Thermal	9,133.36	5.23	4,773.24		4,773.24	5.23
15	NTPC ER	Thermal	129.8	3.26	42.28	32.13	74.4	5.73
16	Kudgi Unit I	Thermal	1,029.55	5.02	516.93	391.81	908.74	8.83
17	NTPC/Barh-1	Thermal	565.52	2.92	165.16	31.22	196.38	3.47

SI.	Source of Power Purchase	Source	Units in MU	VC Rs./kWh	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)	Cost Rs./kWh
18	NTPC/Barh-2	Thermal	667.8	3.33	222.13	49.7	271.83	4.07
19	NTPC/KBUN	Thermal	512.76	2.93	150.43	48.16	198.59	3.87
20	NLC Talabira	Thermal	6,158.72	0.98	603.55	1,281.01	1,884.57	-
	Total CGS		**55,769.11**	**-**	**18,225.91**	**6,871.68**	**25,097.59**	**4.5**
B	**IPPS**			**-**				
21	SEPC	Thermal	643.29	3.47	223.4	160.82	384.23	5.97
22	TAQA (STCMS)	Thermal	1,314.00	4.21	552.6	249.94	802.54	6.11
23	PIONEER Power co. (Penna)	Thermal	-	1.83	-	-	-	
C	Renewables			-				
24	Windmill	Wind	3,750.37	3.61	1,355.55		1,355.55	3.61
25	Co-generation	Other RE	347.07	3.97	137.86	66.51	204.37	5.89
26	Biomass	Other RE	2.1	6.18	1.3	0.39	1.69	8.04
27	Captive generation	Other RE	15.18	2.35	3.57	-	3.57	2.35
28	Solar	Solar	9,146.59	4.48	4,095.65		4,095.65	4.48
29	Traders-MTOA	Traders	572.06	4	228.74	24.05	252.79	4.42
30	Traders-LTOA	Traders	7,436.75	2.6	1,931.94	1,627.95	3,559.89	4.79
31	Traders -STOA	Traders	572.06	3.58	204.65	-	204.65	3.58
32	Power Exchanges	IEX	2,265.43	6.38	1,445.27	-	1,445.27	6.38
33	STOA Charges	IEX				74.85	74.85	
34	**Total**		**81,834.00**		**28,406.45**	**9,076.18**	**37,482.63**	**4.58**

Annexure 31: Approved Own Generation Expenses for FY 2022-23

SI.	Source of Power Purchase	Source	Units in MU	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)
1	Tuticorin TPS	Thermal	4,629	1,835	1,293.93	3,128.93
2	Mettur TPS I	Thermal	4,713	2,358	841.9	3,199.90
3	North Chennai TPS I	Thermal	3282	1,180	1219.14	2,399.14

SI.	Source of Power Purchase	Source	Units in MU	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)
4	Mettur TPS II	Thermal	2,933	1,462	895.63	2,357.63
5	NCTPS II	Thermal	5866	2,309	1224.72	3,533.72
6	Tirumakottai GTPS	Thermal	266	45	209.12	254.12
7	Kuttalam GTPS	Thermal	374	68	205.94	273.94
8	Basin Bridge GTPS	Thermal	6	54	339.84	393.84
9	Valuthur GTPS	Thermal	1,078	190	302.64	492.64
10	Erode HEP	Hydro	1,117		637.15	637.15
11	Kadamparai HEP	Hydro	864		220.83	220.83
12	Kundah HEP	Hydro	2,221		485.02	485.02
13	Tirunelveli HEP	Hydro	1,145		343.02	343.02
14	Wind	Wind	4.00			
15	**Total Generation**		**28,498.00**	**9,501.00**	**8,218.88**	**17,719.88**

Annexure 32: Approved Own Generation Expenses for FY 2023-24

SI.	Source of Power Purchase	Source	Units in MU	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores
1	Tuticorin TPS	Thermal	4,629	1,835	1337.38	3,172
2	Mettur TPS I	Thermal	4,713	2,359	878.95	3,238
3	North Chennai TPS I	Thermal	3,282	1,181	1238.74	2,420
4	Mettur TPS II	Thermal	2,933	1,463	904.64	2,368
5	NCTPS II	Thermal	5,866	2,310	1234.43	3,544
6	NCTPS III	Thermal		843		843
7	Tirumakottai GTPS	Thermal	266	46	215.92	262
8	Kuttalam GTPS	Thermal	374	69	207.93	277
9	Basin Bridge GTPS	Thermal	6	56	332.97	389
10	Valuthur GTPS	Thermal	1,078	194	308.07	502
11	Erode HEP	Hydro	1,117		640.06	640

SI.	Source of Power Purchase	Source	Units in MU	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores
12	Kadamparai HEP	Hydro	864		224.99	225
13	Kundah HEP	Hydro	2,221		486.21	486
14	Tirunelveli HEP	Hydro	1,145		351.17	351
15	Wind	Wind	4			
16	**Total Generation**		**28,498**	**10,356**	**8,361**	**18,717**

Annexure 33: Approved Own Generation Expenses for FY 2024-25

SI.	Source of Power Purchase	Source	Units in MU	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)
1	Tuticorin TPS	Thermal	4,629	1,836	1396.74	3,233
2	Mettur TPS I	Thermal	4,713	2,360	923.12	3,283
3	North Chennai TPS I	Thermal	3,282	1,181	1259.71	2,441
4	Mettur TPS II	Thermal	2,933	1,464	910.64	2,375
5	NCTPS II	Thermal	5,866	2,311	1286.75	3,598
6	NCTPS III	Thermal	3259	841		841
7	Ennore SEZ	Thermal	1,344	640		640
8	Tirumakottai GTPS	Thermal	266	46	217.71	264
9	Kuttalam GTPS	Thermal	374	70	213.49	283
10	Basin Bridge GTPS	Thermal	6	57	323.96	381
11	Valuthur GTPS	Thermal	1,078	197	317.68	515
12	Erode HEP	Hydro	1,117		639	639
13	Kadamparai HEP	Hydro	864		228.44	228
14	Kundah HEP	Hydro	2,221		488.4	488
15	Tirunelveli HEP	Hydro	1,145		359.69	360
16	Wind	Wind	4			
17	**Total Generation**		**33,101**	**11,003**	**8,565.33**	**19,568**

Annexure 34: Approved Own Generation Expenses for FY 2025-26

SI.	Source of Power Purchase	Source	Units in MU	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores
1	Tuticorin TPS	Thermal	4,629	1,837	1426.33	3,263
2	Mettur TPS I	Thermal	4,713	2,361	972.88	3,334
3	North Chennai TPS I	Thermal	3,282	1,182	1265.88	2,448
4	Mettur TPS II	Thermal	2,933	1,465	927.66	2,393
5	NCTPS II	Thermal	5,866	2,311	1465.11	3,776
6	NCTPS III	Thermal	3910	841		841
7	Ennore SEZ	Thermal	2,151	640		640
8	Tirumakottai GTPS	Thermal	266	47	212.77	260
9	Kuttalam GTPS	Thermal	374	72	210.17	282
10	Basin Bridge GTPS	Thermal	6	58	311.68	370
11	Valuthur GTPS	Thermal	1,078	201	314.61	516
12	Erode HEP	Hydro	1,117		630.65	631
13	Kadamparai HEP	Hydro	864		228.18	228
14	Kundah HEP	Hydro	2,221		489.64	490
15	Tirunelveli HEP	Hydro	1,145		362.53	363
16	Wind	Wind	4			
17	**Total Generation**		**34,559**	**11,015**	**8,818**	**19,833**

Annexure 35: Approved Own Generation Expenses for FY 2026-27

SI.	Source of Power Purchase	Source	Units in MU	Total Variable Cost Rs. Crores	Total Fixed Cost Rs. Crores	Total Cost Rs Crores (5+6)
1	Tuticorin TPS	Thermal	4,629	1,838	1441.92	3,280
2	Mettur TPS I	Thermal	4,713	2,361	987.36	3,348
3	North Chennai TPS I	Thermal	3,282	1,183	1277.72	2,461
4	Mettur TPS II	Thermal	2,933	1,465	919.11	2,384
5	NCTPS II	Thermal	5,866	2,312	1470.54	3,783
6	NCTPS III	Thermal	3,910.00	841		841
7	Ennore SEZ	Thermal	2,151	640		640
8	Udangudi Stage I	Thermal	2,688	659		659
9	Tirumakottai GTPS	Thermal	266	48	211.34	259
10	Kuttalam GTPS	Thermal	374	73	209.55	283
11	Basin Bridge GTPS	Thermal	6	59	310.03	369
12	Valuthur GTPS	Thermal	1,078	205	312.95	518
13	Erode HEP	Hydro	1,117		626.65	627
14	Kadamparai HEP	Hydro	864		231.81	232
15	Kundah HEP	Hydro	2,221		492.73	493
16	Tirunelveli HEP	Hydro	1,145		368.11	368
17	Wind	Wind	4			0
18	**Total Generation**		**37,247**	**11,684**	**8,860**	**20,544**

Annexure 36: Approved ARR and ACOS for the Control Period from FY 2022-23 to FY 2026-27 (Rs. Crore)

Sl.	Particulars	FY 2022-23	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27
1	Power Purchase Cost	34,061	34,028	35,302	37,245	37,483
2	TANTRANSCO, PGCIL & SLDC charges	7,901	8,547	9,535	10,527	11,494
3	Generation cost (Own Generation Plants)	17,720	18,718	19,569	19,833	20,545
4	Operation and Maintenance Expenses	9,979	10,670	11,408	12,060	12,750

Sl.	Particulars	FY 2022-23	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27
5	Depreciation	1,586	1,828	2,060	2,316	2,411
6	Interest on Loan Capital	4,608	4,984	5,423	5,485	5,387
7	Interest on Working Capital	6	15	55	81	69
8	**Gross ARR**	**75,860**	**78,791**	**83,351**	**87,547**	**90,139**
9	Less					
10	Non-tariff revenue	2,114	2,612	2,713	2,820	2,932
11	Other income	1,806	1,286	1,120	1,120	1,120
12	**Net ARR**	**71,940**	**74,892**	**79,518**	**83,608**	**86,087**
13	Energy sales	86,166	89,882	93,740	97,936	102,342
14	**Average Cost of Supply (Rs./kWh)**	**8.35**	**8.33**	**8.48**	**8.54**	**8.41**

Annexure 37:Category wise cross subsidy approved by the Commission

Tariff	Category of Consumer	FY 2022-23		FY 2023-24		FY 2024-25		FY 2025-26		FY 2026-27	
		ACOS	ABR	ACOS	ABR	ACOS	ABR	ACOS	ABR	ACOS	ABR
	HIGH TENSION										
IA	Registered factories, textiles, tea estate, Software Industries etc.*	8.35	8.96	8.33	9.28	8.48	9.61	8.54	9.96	8.41	10.31
IIA	Govt. Educational Institutions, Govt. Hospitals, Water supply etc.*	8.35	9.73	8.33	10.12	8.48	10.53	8.54	10.93	8.41	11.39
IIB	Private Educational Institutions, Cinema Theatres & Studios*	8.35	10.93	8.33	11.36	8.48	11.81	8.54	12.28	8.41	12.77
III	Commercial and all categories not covered in other HT categories*	8.35	11.67	8.33	12.06	8.48	12.47	8.54	12.87	8.41	13.28
IV	HT Temporary Supply for construction & other purpose	8.35	15.57	8.33	16.2	8.48	16.85	8.54	17.52	8.41	18.22
	LOW TENSION										

Tariff	Category of Consumer	FY 2022-23		FY 2023-24		FY 2024-25		FY 2025-26		FY 2026-27	
		ACOS	ABR	ACOS	ABR	ACOS	ABR	ACOS	ABR	ACOS	ABR
IA	Domestic , Hand Loom etc.	8.35	5.95	8.33	6.19	8.48	6.44	8.54	6.69	8.41	6.96
IB*	Huts in Village panchayats, TAHDCO etc.	8.35	9.13	8.33	9.5	8.48	9.88	8.54	10.27	8.41	10.68
IC	LT Bulk supply for railway, defense colonies etc.	8.35	9.48	8.33	9.88	8.48	10.29	8.54	10.73	8.41	11.18
ID	Domestic Common Supply	8.35	8.98	8.33	9.34	8.48	9.71	8.54	10.1	8.41	10.5
IIA	Public Lighting and Public Water Supply & Sewerage	8.35	9.32	8.33	9.74	8.48	10.17	8.54	10.62	8.41	11.1
IIB (1)	Government and aided Educational Institution, Government Hospitals etc.	8.35	11.88	8.33	12.54	8.48	13.24	8.54	13.99	8.41	10.84
IIB (2)	Private Educational Institution.,	8.35	13.97	8.33	13.82	8.48	13.73	8.54	13.71	8.41	13.74
IIC	Actual place of public worship, Mutts and Religious Institutions	8.35	9.62	8.33	9.92	8.48	10.23	8.54	10.55	8.41	10.88
IIIA (1)	Cottage and Tiny Industries	8.35	8.44	8.33	8.82	8.48	9.22	8.54	9.64	8.41	10.08
IIIA (2)	Power loom etc.	8.35	8.05	8.33	8.39	8.48	8.74	8.54	9.11	8.41	9.49
III B	Industries not covered under LT Tariff IIIA(1), IIIA(2) incl. IT	8.35	11.05	8.33	11.48	8.48	11.93	8.54	12.4	8.41	12.88
LT IV	Agriculture and Govt. seed farm etc.	8.35	4.46	8.33	4.48	8.48	4.5	8.54	4.42	8.41	5.55
LT V	Commercial and all categories not covered in other LT categories	8.35	11.4	8.33	13.38	8.48	14.29	8.54	15.04	8.41	15.84
LT VI	Temporary supply other than Domestic and Lavish illuminations	8.35	32.99	8.33	34.94	8.48	37.01	8.54	39.21	8.41	41.55
	TOTAL	**8.35**	**8.06**	**8.33**	**8.43**	**8.48**	**8.71**	**8.54**	**8.96**	**8.41**	**9.61**

Annexure 38:Category wise cross subsidy approved by the Commission

		FY20				FY21				FY22			
		True-up Filed		Trued-up approved		True-up Filed		Trued-up approved		True-up Filed		Trued-up approved	
Particular	Supply Share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share	Total ARR	Supply share
O&M xpenses	35%	8,179	2,863	8,272	2,895	8,448	2,957	8,708	3,048	8,937	3,128	8,937	3,128
Depreciation	10%	1,406	141	1,367	137	1,539	154	1,539	154	1,457	146	1,457	146
Interest on Loan	10%	4,403	440	3,421	342	5,340	534	3,430	343	6,266	627	4,192	419
Interest on WC	90%	42	38	0	0	0	0	0	0	60	54		0
Return on Equity	10%	492	49	0	0	626	63	0	0	775	78		0
Other Expenses	10%	2,385	239	2,204	220	3,088	309	2,939	294	25	3		0
Less: NTI	0%		0		0		0		0	1,731	0	1,731	0
Total		**16,907**	**3,769**	**15,264**	**3,594**	**19,041**	**4,016**	**16,616**	**3,839**	**15,789**	**4,034**	**12,855**	**3,693**
Energy Sales	MUs		77,391		76,974		73,622		73,434		80,759		83,867
Operating Cost (Supply)	Rs./kwh		0.49		0.47		0.55		0.52		0.50		0.44