BEFORE THE MAHARASHTRA ELECTRICITY REGULATORY COMMISSION
13th Floor Centre No.1
World Trade Centre, Mumbai-400005
IN THE MATTER OF:

Comments and Suggestions on "Draft Multi Year Tariff Regulations, 2019"

SUBMISSION FROM PRAYAS (ENERGY GROUP), Pune

18th June 2019

MERC vide its public notice dated 28th May 2019, invited comments and suggestions on the "Draft Multi Year Tariff Regulations, 2019." The present submission is in response to the said notice and the draft regulations as well as the explanatory memorandum published by the Commission. We request the Commission to accept this submission on record and allow us to make further submissions in this regard, if any.

1 Approach and Perspective

The objectives behind the introduction of a multi-year tariff (MYT) process can be detailed as follows:

- Providing regulatory certainty to consumers, utilities and investors.
- Minimising perception of regulatory risk.
- Facilitating sound planning practices and processes.
- Addressing risk sharing mechanism between utility and consumers based on controllable and uncontrollable factors.
- Improving operational efficiency and reducing tariff in the long run.

Therefore, for any MYT exercise to be successful there needs to be:

- Reliable baseline data for making future projections.
- Rigorous and scientific demand forecast.
- Long-term power purchase and capital expenditure plans which should be followed with necessary coordination between different utilities and generators.
- Continuous monitoring and evaluation of trajectories for various performance parameters.
- Co-relating MYT exercise with supply and service quality and financial performance of the utility, benefits of which should accrue to consumers in the form of predictable costs and reliable service.

The MYT exercise becomes even more crucial in the current sector context with increasing sales migration and resultant loss in cross-subsidy revenue, increasing cost of supply and growing uncertainty in demand. With fast paced changes taking place in renewables and storage, it is crucial for the regulatory commission to provide regulatory certainty for small consumers and investors alike and this underscores the need for a well-designed MYT framework which provides regulatory certainty and clarity that can help the sector plan in a dynamic, flexible fashion to adapt to this changing environment.

In this context, the MERC has proposed some changes in tariff regulations similar to the recently notified CERC MYT regulations, 2019 for the period of FY19 to FY24. Along with several of these progressive regulations, it is imperative that the Commission also adopt many of the processes followed by CERC to ensure extensive stakeholder consultation before finalising the regulations. Some of these are detailed below:

1.1 Need for a public consultation process and public hearing

The Multi Year Tariff Regulations provides the crucial framework for assessment of investment, costs, performance and tariffs for the next five years for generating companies, transmission and distribution licensees and the load dispatch centre in the state. Given its importance, it is crucial that the regulatory framework be discussed through wide-spread stakeholder consultation. Such consultation would help reduce ambiguity, address implementation and operational issues and adapt regulatory provisions to suit realities and considerations specific to the state of Maharashtra. The MERC should maintain the tradition of having public hearings while finalising important regulations such as, the Multi-Year Tariff Regulations. In fact, CERC also conducted public hearing[1] as part of the stakeholder consultation process while finalising the recent regulations. We strongly urge the Commission to make public hearing a part of the process to finalise these crucial regulations.

1.2 Need for submission of baseline historical data to evaluate amendments

Significant performance improvements and changes have taken place across the MYT Control Periods. While finalising the performance norms for the next Control Period, it is suggested that:

- Commission should direct all utilities to submit historical performance vis-à-vis the performance norms stipulated in the MYT regulations for the 2nd and 3rd Control Periods along with time-series analysis of this data.
- Past performance trajectories which can inform finalisation of future performance norms, especially those which have implications for more recently introduced norms and statutory requirements, should also be published.
- Details of compliance with various directives issued under the MYT and MTR tariff orders should be published.
- All data should be published in excel sheets as per formats prescribed by the Commission within the time period as stipulated by the Commission.
- Commission should publish all the information submitted by utilities prior to the public hearing so that it can inform public comments and the consultation process.

[1] For more details, please see: http://www.cercind.gov.in/2019/whatsnew/PN.pdf

It is important to highlight that the CERC directed all generating companies and licensees to submit such information before finalising the regulations[2] and the operational data was published by CERC[3] prior to the public process. Such a practice should also be adopted by MERC.

1.3 Need for a statement of reasons and transparent sharing of public comments along with final regulations

Given that the principles and processes for determination of tariffs, cost trajectories, performance norms and principles for pass through of costs for all licensees and generating companies will be on the basis of the finalised regulations, transparency in the public consultation process is crucial. To further this, the Commission should:

- **Publish the submissions of all stakeholders in response to the public notice:** Such a practice is followed by the CERC[4]. Such detailed documentation in the public domain helps stakeholders understand the perspective and constraints of all concerned parties.

- **Publish a statement of reasons along with the final regulations:** For all crucial regulations, MERC has been publishing a detailed statement of reasons along with the finally notified regulations. As this statement provides the rationale for the approach in the final regulations and comments on the submissions and concerns raised by stakeholders in this regard, this publication should be part of this crucial process as well. The CERC has also published a detailed statement of reasons as a part of its recent MYT regulations[5].

Publication of all stakeholder comments as well as the statement of reasons would also serve to clarify the position of the Commission and reduce ambiguity in the interpretation and implementation of the regulations. It could also potentially reduce future litigation due to lack of clarity.

1.4 Many progressive suggestions in the draft regulations need to be retained

The draft regulations have many progressive and positive provisions which should be retained in the final regulations. These provisions provide much needed clarity and some of them also would ensure more efficient operations in the sector. Some of these provisions are listed below:

- Mandating competitive bidding as per Section 63 of the Electricity Act for all future capacity addition (Draft Regulation 19.3)
- Explicit disallowance of recovery of fuel surcharge on account of disallowed T&D losses.(Draft Regulation 10.8)
- Linking crucial performance metrics to the Return on Equity finally provided to generating companies and the distribution business (Draft Regulation 29)
- Specification of financial prudence in the context of projected generation and capital expenditure (Draft Regulation 23.3 and 23.4)

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[2] For more details, please see: http://www.cercind.gov.in/2017/orders/L.pdf
[3] For more details, please see: http://www.cercind.gov.in/O&M_Data.html
[4] For more details, please see: http://www.cercind.gov.in/ListOfStakeholders2.html
[5] For more details, please see: http://www.cercind.gov.in/2019/regulation/SOR145.pdf

- Explicit disallowance of particular expenses in project capital costs (Draft Regulation 24.1)
- Clarification on depreciation being used for recovery of loan repayment and depreciation in excess of the debt component being used for repayment of equity (Draft Regulation 28.7)
- Clarification on treatment of gain and loss sharing while computing carrying cost (Draft Regulation 33)
- Specifying that carrying cost incurred on account of delay in filing Tariff and Mid Term Review petitions will be disallowed (Draft Regulation 5.1 and 8.1)
- Specifying cut-offs and prudence checks for additional capitalisation (Draft Regulation 25.2)
- Provision of rebates to consumers for online payments as determined by the ERC (Draft Regulation 36.3)
- Ensuring that savings in repair and maintenance expenses are not off-set against other O&M expenses to ensure funds are spent on R&M (Draft Regulation 74.6 and 83.6)

1.5 Some provisions from 2015 MYT regulations to be retained for the next control period

While many of the provisions from the 2015 regulations have been retained, some extremely crucial and progressive provisions which have significant implications on planning and incentivising efficiency improvements have been removed in the current draft. These include:

- Removal of mandate for submission of ten year power procurement plan as specified in Regulation 19.9 of the 2015 MYT regulations
- Removal of explicit requirement of public process for approval of PPAs as specified in Regulation 20.5 of the 2015 MYT regulations
- Changing the definition of cut-off date such that it could be extended by about 12 more months from date of commercial operation

With respect to the above points, it is suggested that the progressive provisions of the existing (2015) regulations be retained in the final amendment.

1.6 Commission should capitalise on current opportunity to initiate urgent steps to ensure much needed changes in the sector

With the increasing cost of supply of power, rising competitiveness of alternate supply options for large consumers and increasing financial losses of utilities in the state, there is a need for urgent action in the sector to enable efficient operation of the generation and distribution utilities in the future. The Commission can use this opportunity to initiate processes towards tariff reforms to ensure that utilities, especially the distribution companies, are able to cope with the major sectoral shifts initiated by the inevitable shifts in market and technological developments. Many of these measures would imply substantial but necessary changes in operations and should be done with extensive stakeholder consultation in the coming years. Some of these measures to improve planning and efficiency in operations are discussed in the submission and are highlighted below:

- Mandating all 1 MW+ consumers to arrange for supply options via individual contracts to meet all their demand such that they are not subject to regulated tariffs.

- Ensuring that small consumers are protected from tariff shocks which are likely given future uncertainties by linking their tariff increase to inflation.
- Utilising the parallel license framework in Mumbai to enable retail competition and choice for consumers in these areas.
- Specifying caps on variations in specific uncontrollable costs such that variations above these specifications are not automatically passed through to consumers.
- Ensuring cost allocation studies for separation and wires and supply function of the distribution licensees are conducted in the next two years
- Conducting studies to analyse O&M activities that should not be classified as non-DPR capital expenditure by utilities before the onset of the MYT period.

Many of these changes are detailed in the following sections of the submission. In addition there is a need for clarity on the mode of implementation of many of the proposed regulations. These are highlighted in the following sections.

2 Power Procurement

2.1 Mandating competitive bidding for all capacity addition

According to clause 19.3 of the draft regulations, all future procurement of short-term or medium-term or long-term power by the distribution licensees shall be undertaken only through competitive bidding and in accordance with the Section 63 of the Electricity Act 2003. This is a very important change and it is also in compliance with the principles for capacity addition planning laid out by the Commission vide its Order dated 27th March 2018 in case no 42 of 2017, which mandates the distribution licensees (in this particular case, MSEDCL) to undertake any new capacity addition only after establishing competitiveness of the rates of such power procurement. Similarly, even in case of the Mumbai licensees, in order to discover economical tariffs the Commission has repeatedly issued directives to ensure that power procurement is undertaken through bidding as per the provisions of Section 63.

In light of these existing directives and considering the efficiency gains that can be achieved through bidding based power procurement, we feel that the proposed regulation is a **much needed welcome step** and if implemented in letter and spirit, it can go a long way in terms of ensuring optimal and cost-effective power procurement.

Further, in order to remove any procedural ambiguity, it is suggested that the Commission should explicitly add a proviso to the said clause 19.3 making it clear that a **distribution licensee shall need prior approval of the Commission regarding the quantum of power that is sought to be procured and the bidding documents to be used before initiating any such bidding process**.

2.2 Need to retain public process for approving new PPAs

Regulation 20 of the existing (2015) tariff regulations specifies the process to be undertaken by a distribution licensee while seeking approval for any new long- or medium-term power purchase agreement / arrangement. The relevant portions of the said regulation are as follows:

"…

*20.3 The **Petitioner shall submit a duly completed draft Public Notice for the Commission's approval as per the stipulated template, for publication as and when intimated by the Commission**.*

20.4 Upon receipt of a complete Petition accompanied by the requisite information, particulars and documents in compliance with the requirements specified in this Regulation, the Petition shall be admitted and the Commission or its Secretary or designated Officer shall intimate to the Petitioner that the Petition is ready for publication.

*20.5 The **Petitioner shall, within three days of an intimation given to it in accordance with Regulation 20.4, publish a Public Notice, in at least two English and two Marathi language daily newspapers widely circulated in the area to which the Petition pertains, outlining the salient features of the proposed agreement or arrangement for power procurement and the impact on the power procurement cost and Tariff, and such other matters as may be stipulated by the Commission, and inviting suggestions and objections from the public**:*

*Provided that the **Petitioner shall make available a hard copy of the complete Petition to any person at such locations and at such rates as may be stipulated by the Commission**;*

*Provided further that the **Petitioner shall also provide the Petition filed before the Commission along with all regulatory filings, information, particulars and documents in the manner stipulated by the Commission on its internet website**:*

*Provided also that the **web-link to the information mentioned in the second proviso to this Regulation shall be easily accessible, archived for downloading and shall be prominently displayed on the Petitioner's internet website**:"*

(Emphasis added)

Unfortunately, under the corresponding Section 21 of the proposed draft regulations, the requirements of due public process have been removed, which is not desirable.

Power purchase cost is one of the most significant cost components, accounting for 60-80 per cent of the total cost of supply. Further, with increasing demand uncertainty on account of sales migration and changes in demand patterns, and considering the financial, environmental and resource lock-in risks associated with power purchase from conventional sources such as thermal, nuclear or large hydropower projects, it is of utmost importance to ensure highest degree of transparency and accountability while allowing any decisions regarding new power purchase arrangement or agreement.

Therefore, considering the importance of power purchase decisions and their significant impact on consumer tariff, we feel that the existing provisions under Regulation 20 of the 2015 MYT regulations that enable greater transparency and accountability, in this regard should be retained.

In fact the Commission can further strengthen such provisions by not just mandating publication of information, but also introducing due public process in the form of a public hearing in case of such important matters.

Further, in order to better track and monitor the power purchase planning and capacity addition process, the commission should undertake half yearly or annual review of the power purchase plan in presence of the concerned licensees and authorised consumer representatives, and the findings of the review should be made public along with all the relevant data and assumptions.

2.3 Change in the definition of cut-off dates for cost plus projects

"Cut-off Date" is an important parameter, especially in case of generation companies, as the project costs incurred till this date are considered by the Commission for recovery through the fixed charges. Similarly, the additional capital expenditure incurred after commercial operation till this date is considered for cost recovery. Thus, the cut-off date is an important parameter to demarcate the timeline up to which, costs incurred after commercial operation can be allowed, subject to prudence check.

The existing regulations allow for a period of two years after the date of commercial operation to be considered as the cut-off date, whereas the proposed regulations have extended it by one more year, thus allowing three years from the date of commercial operation of the project.

In this regard, it is important to highlight that there have been excessive delays (on an average two years at least) in the commissioning of all the Section 62 projects in the past two control periods. Further, generating companies have often failed to take timely actions with regard to mandatory capital expenditure such as that concerning compliance with environmental norms or for meeting conditions specified in the environmental clearance, etc. even post such delay in commissioning. Considering this track record of the generating companies in terms of project completion activities, relaxation in the cut-off date might encourage further laxness in performance.

Therefore, it is our submission that if the intention is to remove ambiguity, as stated in the explanatory memorandum, the definition of Cut-off date could be modified as follows: *"Cut-off Date" means the last day of the calendar month* ***after twenty-four months*** *from the date of commercial operation of the project;*

2.4 Need for flexible, dynamic, long-term planning processes

In order to ensure prudent power purchase planning, the existing 2015 MYT regulations require the distribution licensees to submit at the beginning of the MYT period, a detailed forecast of their demand-supply position for the next ten years. In this regard, Regulation 19.9 of the existing 2015 MYT regulations states as follows:

> *"The Distribution Licensee shall also submit the* ***demand-supply position on an indicative basis and broad power procurement plan for the ten-year period*** *commencing from April 1, 2016,* ***indicating the various sources of power purchase and mix of long/medium/short term power purchase, and steps proposed to optimise the power purchase cost over that period****, along with its Petition for determination of Tariff for the Control Period from April 1, 2016 to March 31, 2020, in accordance with Part A of these Regulations."* (Emphasis added)

Planning is an extremely important aspect of power purchase and such provision gives consumers as well as the Commission an opportunity to understand and evaluate the electricity distribution companies (DISCOMs) expectations regarding its demand as well as the options it is considering for meeting the same.

Considering the fast changing demand supply scenario, we feel it is crucial to retain this important clause as it creates an opportunity to deliberate on the various options that the DISCOM is considering for its long/medium/short term supply mix and also the other options to optimise its power purchase cost. With increasing complexity in the sector, such provision should not only be retained in the new regulations, but it should also be strengthened to facilitate use of modern and more robust planning tools using more granular and detailed data.

Considering this, it is our submission that it is extremely important to retain this crucial provision that allows for a meaningful discussion on one of the most crucial parameters of the distribution company's business, namely, power purchase planning and if possible enhance it further to allow more robust and scientific approach to power purchase planning.

2.5 Need for gate closure for sale of unrequisitioned power

DISCOMs and generators in the state have significant surplus, unrequisitioned power which can be sold on the DEEP platform, via bilateral contracts or through power exchanges such that the power can be utilised instead of being backed down. Para 6.2 of the National Tariff Policy, 2016 states that distribution companies should declare unrequisitioned generating capacity to the generators at least 24 hours before 00:00 hours of the day of dispatch enabling generators to sell the power[6]. The Policy provides of equal sharing of gains from sale of such power between the DISCOM and the generator. Many PPAs also enshrine this principal of sharing of gains from sale of unrequisitioned power. However, not much of this unrequisitioned power is sold due to a multitude of reasons. One of them is the fact that DISCOMs retain their right to recall till 4 time blocks ahead of actual dispatch.

Retaining the right to recall so close to the actual dispatch increases the risk of sale of such power for generators. The right to recall is necessary to ensure DISCOMs can meet variation in demand closer to real time as the DISCOMs are, after all bearing the fixed cost for the contracted capacity. However, retaining the right to recall so close to dispatch leads to sub-optimal utilisation of generation resources and reduces the need to ensure better scheduling practices.

In order to ensure better utilisation of surplus capacity, the State Grid Code can be modified to ensure gate closure such that DISCOMs forgo their right the recall three hours before dispatch. This would provide generators space to explore avenues for sale of power. As sale of unrequisitioned power has revenue and cost implications, the Commission is urged to implement gate closure while holding

[6] For more details, please see: http://www.cercind.gov.in/2018/whatsnew/Tariff_Policy-Resolution_Dated_28012016.pdf

DISCOMs accountable for surplus management. Implementation of gate closure has also been proposed by CERC Staff in a discussion paper earlier this year[7].

3 Generation

3.1 Capacity charge tariff design

Following the CERC's footsteps, the draft regulations propose a three-part tariff structure, with two components for capacity charge based on peak and off-peak availability and variable charge component concerning generation related costs. The number of hours of "Peak" and "Off-Peak" periods during a day are proposed to be four and twenty respectively. The hours of Peak and Off-Peak periods during a day will be declared by the SLDC at least a week in advance. The High Demand Season (period of three months, consecutive or otherwise) and Low Demand Season (period of remaining nine months, consecutive or otherwise) in the State will be declared by the SLDC, at least six months in advance.

According to the explanatory memorandum, the main objective of this pricing framework is to ensure maximum availability during peak demand periods. Thus, the primary issue is of accountability of the generators. It is indeed important to address this issue and the MERC is right in introducing a pricing framework that is sensitive to availability during peak demand. However, we feel that the approach proposed in the draft regulations is not the most optimum for the following reasons:

- No guidelines have been specified for SLDC for determining peak and off-peak hours for each month, which can be a cumbersome and tedious task.
- The implementation is unnecessarily complicated, as most of the capacity regulated by the MERC is coal based, and hence unlikely to be very responsive to hourly changes in demand within the same day.

Therefore, it is our submission that the same objective of ensuring availability of generating units during periods of high demand can be achieved through a simpler mechanism by adopting the following approach:

- At the beginning of the year, the SLDC in consultation with the generator and the procurer should decide monthly target availability for a station for the entire year. For this purpose, the twelve months of the year can be divided into three distinct time blocks, say,: a) peak load months (based on demand patterns), b) off-peak load months when the plant does not have scheduled maintenance, and c) off-peak load months when a plant is scheduled for maintenance.
- The generator should be required to announce its planned outages during the year in advance to enable such planning and to bring clarity about the target availability of each plant in each month of the year. There should be no planned outages during peak months.

[7] For more details, please see: http://www.cercind.gov.in/2018/draft_reg/RTM.pdf

- Such monthly normative target availability (inclusive of planned outages), should translate into net normative availability of a given station or unit for at least 85% or as specified by the Commission for that particular unit or station over a year.
- Generators would be required to adhere to these monthly availability targets set by the SLDC and the monthly capacity charge payments would be subject to achievement of the target availability in that particular month. Underachievement of availability would result in pro-rata reduction of capacity charge payable. There should be no provision to offset the under-achievement of availability in peak months.
- For under-achievement in non-peak months, the generator can make-up for loss of availability by declaring proportionately higher availability in the months preceding or following the month of such low availability. Such decision of the generator should be based on consent of the procurer and the outages should be planned accordingly.
- A uniform incentive (independent of peak or off-peak period) of Rs. 0.50 /kWh should be applicable for all scheduled generation in excess of ex-bus energy corresponding to the normative target plant load factor for any given month.

We submit that the above proposed approach is simpler to implement and will effectively achieve the objective of ensuring accountability of generators by ensuring availability during peak demand periods, while also incentivising generation beyond the monthly normative target plant load factor.

3.2 Alternate fuel source price to not exceed 10% of base price

The Provisos to Regulation 49.7 of the proposed draft regulations allows use of alternative fuel supply by coal based thermal generating stations from sources other than those agreed by the generating company and beneficiaries in their power purchase agreement (PPA) for supply from the contracted capacity. Such use is permitted on account of shortage of fuel or optimization of economical operation through blending, without any prior consent of the beneficiary, unless the PPA explicitly requires the generator to seek such consent. The provision allows coal based generating companies to use fuel from such alternative sources up to a price in excess of 10% of the approved base energy charge for that year, without any prior approval from the beneficiaries or the Commission. Only when the price of alternative source of fuel exceeds 10% of base energy charge or the average fuel price, including alternative sources of fuel, that prior consultation with beneficiary is required.

We submit that the proposed provision is inappropriate and can lead to dilution of the commercial responsibility of the coal suppliers to ensure coal availability as per their contract terms and conditions, for the following reasons:

- First of all, as per the amendment to the New Coal Distribution Policy (NCDP) dated July 2013, the Government of India has already specified the quantum of coal that would be supplied from domestic coal and the extent to which coal can be imported in case of shortages, if any. Since the Government has brought about such amendments considering coal availability and likely shortages, there is clearly no reason for the Commission to allow sourcing of coal from alternate sources beyond what has been explicitly identified under the existing laws and coal supply contracts.

- Further, the said 2013 amendment to the NCDP has already been declared as a change in law event by the MERC as well as the CERC, and mechanisms are in place to allow recovery of cost of sourcing imported coal on account of any shortages in domestic coal supply due to this reason. Thus, in case of shortage in domestic coal, the interests of the generator are well protected.
- The Commission must respect such existing fuel policies and fuel supply agreements and not create any parallel mechanism that are likely to dilute accountability of the coal supplier at the cost of the electricity consumers.
- The 2013 NCDP amendment assures coal supply of up to 65% to 75% (depending upon the contract year) of the Annual Contracted Quantity (ACQ). Given this fact, such a blanket provision relaxes accountability of the generator in terms of sourcing least cost fuel i.e. domestic coal by allowing use of alternate fuel that can lead up to 10% increase in energy charge.
- The draft provision ignores the fact that even if the generator is operating at a plant load factor below the level of generation that can be supported by the minimum supply assured under NCDP 2013, it can still choose to source coal from alternate sources (such as imports or e-auctions). This would increase energy charge by up to 10% of the base rate without any regulatory approval or prior consent from its buyer. This can lead to scenarios where the generator is spending excess amount on fuel procurement as against what is allowed as per the existing FSA and fuel policy.
- Given the lack of transparency in coal requisitioning, supply, and allocation of coal shortage amongst the various coal consumers, such a provision creates various gaming possibilities and a potential neglect by the coal suppliers of the coal requirements of plants regulated under Section 62.

Considering the above points, it is our submission that the said provisos are inappropriate and unmerited and should be removed.

3.3 Treatment and incentives for plants completing useful life

Regulation 42 of the proposed draft regulations deals with the issue of renovation and modernization of plants completing their useful life. The Commission has rightly proposed optimum utilization of these assets by letting the generator and procurer decide the course of action post the useful life of the asset. As matter of principle, the sector must make best efforts to utilize such depreciated assets to meet seasonal and/or peak requirements instead of commissioning new units for such purposes. The commission should ensure that no new capacity addition is permitted until and unless all such existing and functional assets are fully utilised.

Having said the above, the regulations also need to clearly mention that the existing PPA will not be valid after a unit completes 25 years of its operation. In case the existing beneficiary wishes to continue procurement from such capacity post the 25-year period, the procurer and generator should be required to approach the Commission for entering into a fresh contract. The terms and conditions for such contract and its duration should be evaluated by the Commission considering the beneficiary's demand-supply position and alternative lower cost sources. This requirement of should be explicitly stated in the regulations.

3.4 Compliance with environmental norms and regulations

The MOEFCC vide Notification dated 7.12.2015 has notified the Environment (Protection) Amendment Rules, 2015 amending the Environment (Protection) Act, 1986. Through the amendment, the existing/applicable environmental norms for all existing as well as future Thermal Power Projects stand amended. Under the amended norms prescribed by the MOEFCC Notification for compliance, all Thermal Power Plants have been categorised as (i) Units installed before 31.12.2003 (ii) Units installed between 1.1.2004 and 31.12.2016 and (iii) Units, which are commissioned after January, 2017. However, it is understood that even a year after the timeline that was specified for compliance, most plants have not taken steps necessary for ensuring compliance.

This is a serious issue concerning thermal generation sector as it adversely affects not just the environment, but also the broader public interest. Section 61 of the Electricity Act 2003 mandates the Commission to formulate regulations considering "*the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments*". Thus, it is the responsibility of the Commission to ensure optimal utilisation of scarce natural resources such as coal and water.

It is understood that in order to comply with the MOEFCC norms, many thermal power plants would need to install some pollution control equipment (PCE) and/or undertake some retrofits to the existing plant machinery. Thus, it implies that ensuring compliance would entail incurring of capital expenditure by the power plants. Learning from the past experience of non-compliance and monitoring failure, it seems necessary to have intermediate milestones to ensure timely execution of proposed capital expenditure projects. Also, commissioning of some of the PCE may require the plant to be shut down which further underscores the need for tracking of progress and ensuring that such outages are well planned and coordinated across the state. Considering this, we propose the following measures to be adopted in this regard:

- Defining the norms notified as per Environment (Protection) Amendment Rules, 2015 as 'Revised Emission Standards' conveys a narrow interpretation as the said rules also include norms for water utilisation and are not restricted or limited to emissions alone. Therefore, it our submission that the same should be defined as "Revised Environmental Regulations / Standards / Norms", as that would be more appropriate.

- While approving any capital expenditure for such compliance, the Commission should mandate the power plants to submit detailed information that would enable it to undertake due scrutiny of the proposed expenditure.

- Additionally, the Commission should establish a web-based transparent system for tracking of progress and achievement of the milestones. The onus of compliance should be entirely on the power plant and non-compliance should be assumed unless the power plant in question reports compliance status to the Commission and submits all the necessary documents.

- If the generating company delays construction or commissioning of any PCE beyond the final milestone, no interest during construction (i.e. IDC) should be allowed on account of such delay, i.e. in such case no increase in IDC beyond the normative value approved by the Commission in the original DPR should be allowed to be passed on to the electricity consumers.

- Draft Regulation 25.4 deals with additional capitalization on account of revised emission standards. The said clause defines the procedure for claiming recovery of the capital expenditure necessary for ensuring compliance with the revised norms. In this regard, it is essential for the regulations to expressly state that any cost disallowance and/or delay in terms of securing cost approval cannot be the ground for non-compliance with the revised emission standards. The said emission standards being a statutory requirement, compliance with the same cannot be subject to any cost approval.

- Regulation 46 deals with operation and maintenance related expenses and also includes provisions pertaining to water charges for thermal power stations. It is important to note that the revised emission standards also prescribe water usage for thermal plants. Therefore, the regulations should include a proviso that explicitly disallows any expenditure on water charges that is over and above the norm prescribed under the revised emissions standards.

4 Process and specifications for Multi-Year Tariff and Mid-Term Review

4.1 Need for ensure public process for tariff determination

Given the flux in the sector, consumers and stakeholders in the sector will have to face tariff and cost uncertainty. In this context, regulatory process and decision making should take place through transparent public processes to ensure legitimacy of institutional processes and decisions. Such processes can also provide valuation insights on impacts and implications of various changes which can inform mid-course correction at a time when flexible, responsive planning is key. To ensure public processes are part of tariff determination the MYT regulations can be amended to:

- **Ensure Technical Validation Sessions**: The third proviso of draft Regulation 14.3 states that the Commission may conduct Technical Validation Sessions (TVS) prior to the admission of tariff petitions. It is suggested that Technical Validation Sessions are treated as indispensible to the tariff determination process as important information and insights can be derived from clarifications and additional data provided by the companies and licensees. Thus, the draft regulation should say that the Commission *shall* conduct TVS prior to the admission of tariff petitions.

- **Mandate public hearings in multiple locations in the state**: Currently, the draft regulations stipulate that the petitioner and the Commission can invite comments and submissions from the public on the petition submitted. In the spirit of participation, the Commission should also ensure that Regulation 14 of final MYT regulations for the upcoming control period specifies public hearings in multiple locations in the state for the tariff determination process for the distribution licensees and public hearings in at least one location for the determination of tariffs for all other generating companies and licensees in the state

4.2 Need for measures to optimise uncontrollable costs

While it is true that there are many factors which are beyond the control of the utilities which could increase uncertainty in cost determination, it is also a fact that many actions can be taken by utilities to mitigate risk and uncertainty and thus reduce the variation in uncontrollable costs. There is a need to improve current planning and risk management processes. However, utilities have not incentive to invest in such processes under a cost-plus framework as the costs variation due to various risks are passed through to consumers. Going forward, with emerging competitive supply options via open access and captive generators, many consumers will not be willing to bear cost of risks incurred by the regulated utilities. Therefore it is imperative that DISCOMs take urgent action to try and rein in many of these costs which are deemed as uncontrollable. To some extent, action can be taken by generating companies and distribution licencees to mitigate increase in fuel price (active interventions and engagements with coal sector actors, participation in practices for coal rationalisation) variation in sales (better estimation of migration of sales due to open access and captive options, more accurate and scientific techniques for demand estimation), variation in power purchase cost (efforts to optimise generation and procurement from various sources), variation in transmission charges (measures to increase accountability for transmission investments and operations). To kick-start this process, the Commission can:

- Specify caps on the costs which can be recovered as uncontrollable from consumers due to variations in fuel price, sales, power purchase cost and transmission charges.

- The caps can be high in the initial control period can be reduce over time. For example, in the upcoming control period up to 20% variation can be passed on with a 5 percentage point reduction in the subsequent control period.

- The company or licensee would require regulatory approval for passthrough of any cost above this specified cap for the stipulated period.

The first proviso of draft regulation 8.2 states that even trajectories and principles of tariff and cost determination can be modified at the time of mid-term review. For the MYT period, there is therefore little guarantee of tariff and cost certainty which is why such caps on uncontrollable costs become necessary.

4.3 Need to increase specification of trajectories to track and improve performance

Draft Regulation 7 specifies that the Commission can stipulate trajectories for certain variables to improve efficiency. These variables can include but are not limited to transmission losses, distribution losses, collection efficiency, and payment efficiency. Along with these variables it is suggested that the regulations explicitly state the following variables for which trajectories can be specified by the Commission:

- **Actual Working Capital Borrowing of the DISCOMs, transmission licensees and generating companies**: The actual working capital borrowings or short-term liabilities of utilities are much higher than the regulated working capital borrowing estimated for passthrough to consumers. These are incurred due to strained cash flows and are clear indication of the financial stress faced by utilities due to multiple factors. Unlike collection efficiencies and average revenue gaps, the working capital borrowings of DISCOMs are not tracked and reported in a systematic manner in the power sector. To understand the scale of the issue faced by utilities and to address them before another bailout is required, it is necessary to track and mitigate such borrowings. The Commission, as part of the MYT process can track the extent of such borrowings and should provide trajectories for calibrated, gradual reduction (specified say, as a percentage of the annual ARR) to assist the financial turn-around of these businesses.

- **Payment efficiency for state government subsidies**: The Commission can also track and report the actual payment of subsidies as compared to the commitment of the state government. This can be done for a year or on a cumulative basis, including pending payments. The Commission can also specify trajectories for improvements in payments such that the DISCOMs can take necessary actions to ensure timely payments.

4.4 Need for clarity on operationalisation of gain and loss sharing mechanism after the introduction of ceiling tariffs

Draft Regulation 17 states that the tariff determined by the Commission for the generation and transmission utilities shall be the ceiling tariff. Therefore:

- Companies can charge lesser than the regulated tariffs as long as beneficiaries agree and the commission is intimated
- Charging lower tariffs may also take place with deviation and improvements from cost and performance norms approved by the commission.
- Details of actual performance and cost incurred should be shared at the time of true-up and losses in any form on account of this are to be borne by the Utilities

These regulations can usher in increased efficiency and cost-competitiveness if it generates interest from utilities. However, clarity is needed on how gain and loss sharing will be applicable at the time of true-ups in such cases. This is because all costs savings due to increased efficiency, over and above the stipulated norms are passed onto consumers through tariff rebates. In such a case, during the time of true-up it is not clear if the gains will be be evaluated on the basis of the original norms or revised norms agreed to by the Company. Further, it is not clear if gains over and above this will be shared with the consumers. Clarity on this matter is required in the final regulations.

4.5 Need for inflation-linked tariff increase for small LT consumers

With the average cost of supply being more than Rs. 7 per unit, many cross-subsidising consumers are reducing their dependence on the DISCOMs by procuring power form open access and captive generators. With the loss of cross-subsidy, small LT consumers will have to bear the burden of increased costs. Given the multiple, pressing commitments of the state government and limits to subsidy growth, the tariffs of these consumers have to increase. However, such increase can take place on a gradual basis to protect many small, poor consumers from tariff shock. This gradual increase can be stipulated in the MYT regulations by linking tariff increase for agricultural consumers and LT commercial, industrial and domestic consumers using less than 300 units per month to inflation. Thus, the tariff increase for LT consumers, specifically, agricultural consumers as well as domestic, industrial and commercial consumers using less than 300 units should not be higher than the rate of inflation in the past year. The estimation for rate of inflation could give a higher weightage for Consumer Price Index than the Wholesale Price Index as it concerns retail tariffs. The draft MYT regulations already propose to continue the practice of linking Operation and Maintenance expense norms to inflation. In a similar fashion linking small consumer tariff increase will ensure tariff certainty for consumers and gradual increased revenue recovery for DISCOMs from these consumers.

5 Need for proactive steps to recognize and facilitate inevitable segregation of the wires and supply business of DISCOMs

5.1 Separation of wires and supply business not just based on allocation matrix

As per Draft Regulation 70, every distribution licensee shall maintain separate accounting records for the wires and supply business and shall prepare an allocation statement to enable separate tariff determination for each function. The draft regulation also states that in case accounting segregation is not done, the ARR will be segregated based on the allocation matrix specified by the Commission.

Going forward an accurate estimation of costs and revenues attributable to the wires business and the supply business is essential. Despite several directions to the utilities to ensure separate accounting records, there are been limited efforts to ensure this by DISCOMs in Maharashtra. In fact, privately-owned distribution companies do not even maintain separate accounts for their generation, transmission and distribution business. Before the commencement of the upcoming control period, the DISCOMs should initiate a process of reporting the ARRs of the wires and supply business based on separate accounting records rather than the allocation matrix. To this end, the Commission should:

- Remove the allocation matrix prescribed by the Commission in the MYT regulations
- Mandate that the separate ARRs for wires and supply have to be reported based on separation of accounts
- Specify intermediate milestones to ensure that action is being taken before the commencement of the MYT period.

- Ensure separation of accounts and reporting should take place before the commencement of the Control period with progress reports on significant milestones to the Commission on a periodic basis.

5.2 Need to enable long-term migration of eligible consumers

Open access and captive consumption has increased substantially over the last two control periods. However, many consumers continue to depend on the DISCOM and opportunistically switch between the market and the DISCOM based on price signals. This makes is difficult for the DISCOM to plan power procurement and operations. In order to enable planning in the face of uncertainty, the MYT regulations as well as the Open Access regulations can state that:

- All consumers with the sanctioned load greater than 1 MW can avail supply from the DISCOM only if they sign contracts for supply for a period not less than 1 year.
- In the absence of such a contract, these consumers have to make their own arrangements for supply.
- The tariffs for 1 MW+ consumers will be based on contracts and negotiations with the DISCOM and will not be regulated.
- However, supply to such consumers should not come at the cost of poor supply or increased tariffs for regulated consumers

Such changes will help broaden and deepen power markets and reduce uncertainty in demand for consumers. It would also reduce the requirement to sign firm long term power procurement contracts to cater to this demand. The commission should consider enabling this transformation soon as many of these consumers are reducing their dependence on the DISCOM. Without urgent action to enable a smooth transition, the cash strapped DISCOMs will face a financial crisis in the face of increasing costs, negligible cross subsidy and limits to possible tariff increase.

5.3 Enabling competitive framework for implementing parallel licencing in Mumbai

Operationalization of the parallel license mechanism in Mumbai remains a unique experiment. Presence of a parallel licensee offers an opportunity to bring down costs and increase efficiency, though neither of these expectations has been met so far. One of the major criticisms of the Mumbai experiment has been the use of “cost-plus” regulation approach which sets poor incentives for the licensees to be efficient. With recoveries of claimed expenditure assured, there is no incentive for the licensees to exercise economy and/or improve planning. This is plain to see in the case of Mumbai.

Regulatory certainty for recovery of expenditure undertaken on wires (including network expansion) and supply would lead to continued need for cross-subsidy surcharge and regulatory asset charge and thus, the resultant tariff uncertainty for consumers will also continue. While cost-plus approach is inherently inefficient, the existence of parallel licensees makes it particularly worse. Therefore, it is our submission to use the present MYT process as an opportunity to develop a separate regulatory framework for regulating the parallel licensees in Mumbai. Such framework should be conducive for competition and should create possibilities for reducing costs. We submit that it is possible to device such framework within the exiting legal and regulatory provisions.

The Commission should separately undertake a public process to deliberate on the contours of such framework. Based on our study of the parallel license arrangement in Mumbai[8], we feel that a scheme on the following lines could be considered:

- The Commission should freeze the regulatory assets and revenue gaps up to a certain year, say, FY 2020, and allow its recovery from all suburban consumers. However, there should be no true-ups or revenue gap approval beyond this set time period.
- In order to protect the interests of small consumers, the tariffs for domestic consumers consuming 0-300 units per month should be capped at reasonable level. For all other consumers, the commission should just impose a tariff ceiling[9]. In addition, there should be a cap on the wheeling charges and cross-subsidy surcharge. Within the ceiling limit, the distribution companies should be given full flexibility in terms of managing the power procurement, capital expenditure and operations and maintenance costs, so as to maximise their sales and revenue.
- To ensure universal supply obligation, both licensees should be mandated to make their wires available for changeover. Instead of reviewing costs and expenditures of the licensees on annual basis, the Commission should focus its attention on compliance with standards of performance and monitoring of sales and migration process.

The key objective of the proposed scheme is to put an end to the cost-plus approach and the regulatory asset regime, which offers no incentive for the licensees to reduce costs or to improve planning. In contrast, the proposed scheme would ensure recovery of all past dues, but would offer no certainty for recovery of (inefficient) costs in the next control period (i.e. next four to five years).

It offers the licensees complete flexibility to optimise their operations, so long as they operate within the ceiling and adhere to standards of performance. It also offers consumers the choice of negotiating better terms with the companies or other suppliers, without compromising on the interests of the small consumers. Most importantly, while providing flexibility to the licensees and the subsiding consumers, the proposed scheme ensures tariff certainty for the small consumers.

The commission should consider publishing a whitepaper detailing all the issues concerning implementation of such a scheme, and seeking public comments and suggestions from all stakeholders in this regard. Based on the whitepaper and after undertaking due public process, the commission should formulate new regulations for putting into effect such a scheme for at least the next control period.

[8] Prayas (Energy Group): February 2017: *In the Name of Competition: The annals of 'cost-plus competition' in the electricity sector in Mumbai* http://www.prayaspune.org/peg/publications/item/333.html

[9] The proviso to section 61(1)(a) of the Electricity Act, 2003 states: "*… 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."*

6 Capital Expenditure and other expenses

6.1 Public process for in-principal approval of capex

Under draft regulation 24, 25, 58, 73, 92 the commission has to provide approval for capital expenditure projects. As these projects have significant cost and tariff implications for generating companies as well as licensees, it is suggested that the capital expenses approval takes place through a public process.

6.2 Treatment of variation in capitalisation and capital expenditure due to time and cost overruns

Regulation 9.2 (a) and (b) clearly stipulate that variation in capitalisation on account of time and cost overruns and any capital expenditure cost variation due to the same will be treated as controllable factors. Thus, there will be gain and loss sharing with consumers in case of variation. This regulation has been removed in the draft MYT regulations for the next control period. The explanatory memorandum published with the draft regulations justifies this removal by stating that there is no intention to share cost of such inefficiencies with consumers. Thus, the evaluation of time and cost overruns needs to done on a case to case basis and the exercise to determine this will be undertaken at the time of prudence check of the capital cost. To address this, the draft Regulation 24.2 states that prudence checks may be conducted such that it :

- Includes scrutiny of reasonable of expenses, financing plan, interest during construction, use of efficient technology, time and cost overruns etc.

- Entire gains established after prudence check due to variation in capitalisation costs shall be passed onto consumers as tariff rebate

- Losses determined after prudence check shall be shared between the utility and the beneficiaries in a manner stipulated by the Commission

Capital expenses are significant for generation, transmission and distribution companies and there can be substantial improvements in project planning and management to reduce time and cost overruns. Any costs incurred due to force majeure events and change in law events are considered to be uncontrollable costs as per proposed regulation 9.1. All of the reasons for time and cost overruns which cannot be attributed to the inefficiency of the company or licensee can be due to these uncontrollable factors. Thus, it is suggested that the final regulations state that:

- All variation in capital costs due to factors other than those stated in Regulation 9.1 be disallowed by the Commission after prudence check.
- These costs can be attributed to inefficiency and/or poor planning practices of the regulated company or licensee and thus the burden of such costs should not be shared with consumers.

Such a provision would force companies to adopt better planning and management practices and reduce the burden of inefficiency on consumers.

6.3 Charging bank rates to account for interest costs

Draft Regulation 2 (10) defines bank rates as the bank rates declared by the Reserve Bank of India from time to time. As per the draft regulations, this bank rate is the applicable:

- Interest rate to be charged along with refund in case any generating company or licensee charges tariffs over and above the tariff approved by the regulator. (Draft regulation 16.2)
- Interest rate payable on security deposits held from consumers (Draft Regulation 30.11).

Bank rates are policy rates of the RBI and it essentially is the rate at which the central bank lends to other banks. It is typically 2 to 3 percentage points lower than the MCLR, which is the minimum interest rate below which a bank cannot lend. This is not the market rate for lending and thus is not a true measure of the opportunity cost of the revenue over-recovered by the utilities. It is suggested that the interest rate applicable on this refund be charged at the base rate as defined in draft regulation 2 (11) rather than bank rates.

As per the explanatory memorandum, charging bank rates for the interest payable on security deposits will reduce the impact on ARR. However, the first proviso draft regulation 30.11 also states that the licensee can recover the actual interest payable at the time of true-up. This interest amount will be more than the allocation of interest at the bank rate at the time of tariff determination. Thus, charging bank rates instead of base rates only defers recovery of fait accompli costs and increases the carrying cost burden (till the time of true-up) rather than reduce the ARR. It is therefore submitted that is it in consumer interest to charge the base rates rather than the bank rates on interest of security deposits as it will be closer to the actual interest rates paid by the licensee.

6.4 Clarification and specification related to incentives based on asset turnover ratio

The provision of Return on Equity based incentives and penalties for the generation business as specified in draft regulation 29.3, 29.4 and 29.5 are much needed steps to move towards incentive based regulation. Draft regulation 29.5 (i) also provide for additional equity for the distribution business. With respect to this specification it is suggested that:

- **Asset turnover ratio explicitly should not include losses in energy wheeled**: As per draft regulation 29.5 (i) additional equity is provided for improvements in the asset turnover ratio as per the following proposed schedule shown Table 1.

Table 1: Return on Equity incentive for improvements in asset turnover ratio

Additional return on equity provided	For Improvement by Asset Turnover Ratio by at least
0.25%	2%
0.50%	5%
0.75%	8%
1%	10%

Where, $Asset\ turnover\ ratio = \frac{Energy\ Wheeled\ (MU)}{Gross\ Fixed\ Assets\ (Rs.Crores)}$

For a given set of fixed assets, the DISCOMs asset turnover ratio can increase with an increase in the energy wheeled. This can take place by increasing sales to DISCOM consumers, increasing energy consumption by open access and off-site captive consumers or by increasing distribution losses. Thus, if all other variables stay the same, the asset turnover ratios could increase over the years if DISCOMs become more inefficient and increase distribution losses. This inefficiency should not be incentivised with additional return on equity. It is therefore suggested that the definition of asset turnover ratio be explicitly defined on the basis of energy sales to DISCOMs and final energy consumption by open access and captive consumers to get a better sense of the utilisation of the DISCOMs network rather than incentivise its inefficiency.

- **Return on Equity based incentives should also be available for transmission utilities**: Incentives similar to those specified in Regulation 29.5 (i) can be specified for transmission utilities as well on an energy wheeled basis (after explicitly accounting for losses). The base return on equity can also be lowered to offer additional equity based on performance.

6.5 Need to specify RoE related incentives for supply business

The supply business earns the highest return on equity due to perceived risk and uncertainty in the business. However, this business should also be subject to performance linked incentives and disincentives. As the retail supply business is responsible for the supply and service quality to consumers, the return on equity can be linked to supply and service quality related parameters. One way to do this could be based on the performance of the DISCOMs with respect to standards of performance specified in the Standards of Performance Regulations (SoP), 2014. For example, an additional return on equity of 0.5% can be provided if overall standards of performance are met. The basis for providing additional equity or introducing a reduction in equity based on supply and service quality should be finalised by the Commission based on past performance as reported in quarterly SoP reports submitted under Section 59 (2) of the Electricity Act.

7 Transmission, Distribution and Supply

7.1 Clarification on implications of change in the definition of EHV

The draft regulations define Extra High Tension (EHT), High Tension (HT) and Low Tension (LT) on a voltage-wise basis such that:

- EHT refers to all voltages which are above 33 kV (Draft Regulation 2.1 (34))
- HT refers to all voltages above 11 kV but below 33 kV, including 33 kV (Draft Regulation 2.1 (46))
- LT refers to voltages below 11 Kv (Draft Regulation 2.1 (52))

This is a shift from what is currently identified as Extra High Voltage or Tension (66 kV and above)[10]. Such a shift could have implications on the estimation of losses, applicability of tariffs, estimation of cross

[10] For more details please see Page 457, 504, 573 of MERC Order in Case No. 195 of 2017: http://www.mercindia.org.in/pdf/Order%2058%2042/Order-195%20of%202017-12092018.pdf

subsidy surcharge and applicability of wheeling charges. In this context, clarity is needed on the treatment of:

- **Loss estimation for the purpose of energy balance**: Currently the methodology followed by the Commission assumes that the EHT losses are the same as the intra-state transmission losses at about 3.30%. The losses at 33kV level are much higher (at about 6% for MSEDCL) and are treated separately for estimation of line losses, overall losses and energy requirement. The voltage-wise treatment of losses, in the energy balance methodology should ensure that the EHT losses are not treated the same as the inter-state transmission losses, especially if energy input and drawn above 33 kV but below 66 kV is also being considered. Such an assumption could lead to under-estimation of non-LT losses.
- **Applicability of wheeling charges for consumers at 33 kV:** For the current control period, the Commission has been charging a 3 part tariff from regulated consumers consisting of fixed charges, energy charges and wheeling charges. These wheeling charges are not applicable on EHT consumers (currently, consumers which connected at 66 kV and above). This is because these consumers are presumably not using the distribution network infrastructure for wheeling power. However, if the definition of EHT is changed to include consumers connected above 33 kV, the distribution company could incur cost for wheeling the energy required by these regulated consumers. In fact, MSEDCL has estimated that about 14% of its Gross Fixed Assets can be mapped to the 33 kV voltage level and about 10% of MSEDCL's consumers are connected at the 33 kV level. The cost incurred for wheeling energy for consumers connected above 33 kV level is not clear. Open Access consumers connected at the EHT level also do not pay any distribution wheeling charges at present. If the definition is changed such that consumers connected above 33 kV are considered EHT consumers, it should be clarified in the tariff orders in these regulations that appropriate wheeling charges to ensure cost recovery for the DISCOMs will be applicable on these consumers.

7.2 Clarity required that STU tariff determination will take place through a public process

Draft Regulation 63.5 specifies that the State Transmission Utility shall file an MYT petition and well as an MTR petition in the control on the basis of the Base Transmission Capacity Rights of each TSU and the ARRs of each transmission licensee. This is a much needed step and could go a long way in ensuring integrated and timely transmission planning. However, the draft Regulation 5, 6 and 8 dealing with petitions to be filed in the Control Period, MYT and MTR petitions do not explicitly mention STU along with the licensees and generating companies on whom these provisions are applicable. This should be clarified in the final regulations. The Commission should also ensure that the tariff determination process for the STU, like all the other utilities and companies takes place through a public process.

7.3 Subsidy payment

Regulation 99 of the 2015 MYT Regulations and Regulation 101 of the draft regulations detail provisions for the manner of grant of subsidies by the State Government. Delay in committed subsidy payments affects the working capital requirement of DISCOMs as the subsidy revenue is not available in a timely manner to meet day to day expenses being incurred. In order to address the delays, the 2015 regulations and the draft regulations state that:

- Subsidy will be adjusted only on the basis of subsidy actually paid by the Government for the period.
- Any short-fall will be adjusted in subsequent periods until the subsidy is paid

The effectiveness of this provision in the current control period needs to be evaluated based on data on the schedule of subsidy payments and instances where the DISCOMs have charged higher than subsidised tariffs due to delay in payments.

Such provisions, in line with Section 65 of the Electricity Act, 2003 have been utilised by Commissions in Punjab and Bihar to ensure timely payments with limited impacts. In case of delay in payment, such a provision would imply significant tariff hikes for poor subsidised consumers, especially agricultural consumers. Further, it is also likely that in anticipation of future adjustments when the subsidy is provided, consumers may resort in delay in bill payment itself which could reduce the collection efficiency and increase AT&C losses. Additionally in such instances, it is not clear if the delayed payment charge for non-payment of bills in lieu of delays in subsidy payment will be borne by the consumer or the state government. Therefore as such a measure has political as well as implementation issues, it may not be effective as DISCOMs might continue to bear the financial implications of delayed payments rather than passing on impacts to consumers.

To ensure greater accountability for delayed subsidy payments, the final MYT regulations should:

- **Account for interest cost due to delay in subsidy payments**: All interest cost accrued by the DISCOMs due to delay in subsidy payments should not be passed through to consumers. Instead, such costs should be explicitly accounted for as part of future subsidy payments (along with pending payments and future commitments) to be recovered from the state government. This is the practice followed by the Punjab ERC.
- **Ensure quarterly reporting of subsidy payments**: DISCOMs should report category-wise subsidy payments as per the payment schedule on a quarterly basis. Any delays and costs thereof should also be recorded based on actual payments. The mode of payment (via direct budgetary transfer, adjustment of electricity duties or loans) should also be stated in these reports. These reports should be submitted to the Commission every quarter and should be available on the DISCOM website.
- **Ensure tracking and reporting of payment efficiency of subsidy**: Payment efficiency of subsidy which can be measured as the ratio of subsidy actually paid in a period and the subsidy committed for the period. This can be tracked and reported on a quarterly and annual basis. It can be also reported on a cumulative basis to ensure accountability.

8 Definitions

8.1 Additional terms that can be defined

Along with the definitions added the draft amendment, the final regulations can also include definitions for billing efficiency, collection efficiency, payment efficiency and fuel supply agreement. Additionally, wheeling charges can also be defined as the term is used to refer to a component of tariffs for regulated consumers as well as a charge for open access consumers.

8.2 Clarification on collection efficiency

As per CEA guidelines for Computation of AT&C losses notified in June 2017[11], collection efficiency is estimated based on not just current year receivables but also past receivables. In such a case, the collection efficiency can exceed 100% for a particular year. The guidelines also specify the capping of collection efficiency at 100%. Such an estimation would result in the same values for Distribution network losses and AT&C losses for a DISCOM which has been efficient in recovering past dues. As this is not a reflection of actual current revenue collection, it is suggested that the definition of collection efficiency which the ERC should prescribe should be based on revenue collection for the current year alone.

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[11]For more details, please see: http://www.cea.nic.in/reports/others/god/dpd/guidelines_atc_loss.pdf