NERSA Consultation Paper on

Electricity Price Determination Methodology (EPDM) Rules

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Eskom's Response Submission to Nersa

20 September 2023

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Eskom's Response Submission

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1.1 Deviations from legal requirements

NERSA acknowledges that changes in the regulatory approach can only occur within the legislative framework. However, this statement is contradicted in many instances. Key aspects include:

- *Electricity Regulation Act (ERA)*
  - NERSA must ensure that licensees recover efficient costs and a fair return seem not to be possible any longer in this proposal. The devastating impact of this oversight in the EPDM creates an untenable situation for licensees.
  - The focus on customers' affordability, competitiveness and profitability does not seem to uphold the spirit of the ERA – where a fair balance between customers, licensees, investors, etc is not evident.
  - Draft amendments to the ERA and EPP seem to have become a reality creating further confusion. It is recommended that no review of the methodology should proceed until there are updates of the EPP and ERA
- *The National Energy Regulator Act (NERA) and Promotion of Access to Justice Act (PAJA)*
  - This is extremely important to allow all stakeholders to be provided sufficient information to understand the impacts (as these are missing) so as to engage properly on further developments of the as yet incomplete methodology as well related regulatory requirements.
- *Appropriation Act*
  - NERSA is proposing subsidies in particular favouring certain customer categories that are not included in the National Treasury appropriation act. This is by implication, since the affordability, profitability and competitiveness would be considered in setting tariffs. If the consumer is not paying a cost-reflective price for electricity through a tariff, then the taxpayer would need to pay and this should be guided by national policy.
- *Municipal Finance Management Act (MFMA)*
  - To meet the S42 of the MFMA, Eskom as an organ of state is required to consult on price changes to a municipality to SALGA and National Treasury. This proposed methodology does not require a revenue application that will be used to get to such a price change at an Eskom level.
- *The EPP requirements* in many instances are not complied with. For example:
  - Recovery of efficient costs and fair return at licensee level (Eskom) ***Policy position 1***

- Use of replacement value for the determination of RAB Policy position 1
- Wholesale and retail energy prices must reflect the TOU structure (Policy positions 12, 31, 32, 36, 58).

- *The NERSA codes, licenses and methodologies* are also not complied with, for example on the Tariff Code,
  - Distributors shall be required to submit any tariffs and tariff structural changes to NERSA
  - Energy charges to be reflected on a TOU basis
  - Tariffs to include differentiation to take into account time and /or seasonal variance.

NERSA will need to correct its methodology due to such possible violations of legislation and Government Policy and update its regulatory documents to ensure the methodology is aligned and implementable.

Reference is erroneously made to the initial MYPD methodology not being aligned to prevailing NERSA rules, codes, etc. This is not the case. Thus, it is proposed that any new methodology or rule be aligned to existing regulatory instruments. If need be, certain instruments could be revoked. Not having such order, would result in chaos.

1.2 NERSA consultation roadmap

It is understood that NERSA has consulted on similar proposals since March 2021. Consultation processes have been undertaken during 2021, 2022 and now in 2023. The fundamentals of the NERSA proposals have not changed. This is despite stakeholders pointing to fundamental flaws in the proposals. It is understood the further aspects of this roadmap will still continue up to March 2026. However, in contradiction, NERSA refers to this methodology rules being finalised in November 2023. It is submitted that this finalisation by 2023 is highly unlikely

1.3 Confirmation of what a NERSA methodology should enable

It is evident that after many consultations, NERSA has not arrived at a position where it can provide the EPDM rules or a methodology for the licensees to implement or provide a clear view of how tariffs will be set. The process over the many consultations has not evolved positively and in fact seems to have regressed. The present consultation document is still very much at a descriptive stage, where the possible nature of processes is being explored. It is understood that NERSA will have difficulty in implementing what is proposed in the EPDM.

It is understood that any NERSA methodology should provide regulatory rules that need to be followed by NERSA licensees to achieve the desired outcome. It is submitted that this consultation paper on the "*EPDM rules*" does not seem to meet many of the following minimum requirements.

- The methodology should be in accordance with prevailing legislation and policy.
- The methodology must be aligned to all other NERSA regulatory requirements and NERSA licenses. It should not create any areas of contradiction.
- If any existing methodology, rule, code, etc is being replaced by a new methodology or rule, this needs to be clearly stipulated in the consultation.
- It should be clear and precise on the requirements to be met.
- It should enable the relevant licensees to be in a position to implement the requirements of the methodology.
- It is essential to provide clear timing requirements for the implementation of the methodology
- It is essential to provide clarity on which licensees the methodology is applicable to
- Must be clearly implementable with transparent criteria that are replicable and well understood.
- The requisite information requirements must be known. The support mechanisms need to be known and implementable

1.4 Stakeholder comments have not been considered

Various stakeholders including Eskom have provided many alternative proposals and have been critical of the NERSA proposals in the previous consultation papers. Many stakeholders have significant experience in economic regulation and have provided meaningful contributions. It is submitted that a majority of the contributions made have been completely ignored and responses by NERSA to these contributions are inadequate. It is felt that for the healthy development of a new approach to determining the price of electricity, NERSA is obligated to provide detailed facts, evidence and experience as to why the proposals being made by stakeholders are incorrect. Conversely, NERSA is obligated to provide facts, evidence and experience on how the proposals being made are viable, implementable and meeting the NERSA mandate in accordance with the Electricity Regulation Act (ERA) and Electricity pricing policy (EPP).

1.5 Fundamental flaws have been highlighted – however only terminology addressed

NERSA has clarified that the challenge is the terminology. The statement made is: *"During the public consultation process, it became apparent, that it was necessary to revise the use of terminology and clarify how the pricing principles would be used in the new pricing methodology."* It is unfortunate that NERSA has not addressed the fundamental flaws that have been raised by the majority of the stakeholders and reduced this to a 'mere challenge of terminology' which is a misrepresentation of the facts.

1.6 Key risks related to what is being proposed

Some of the key risks that have been identified include the following

- Decision-making centralised within NERSA with NERSA both setting and approving tariffs.
- Radical big bang change is proposed
- Non-compliance with existing legislation
- Non-compliance with Electricity Pricing Policy.
- Non-compliance with NERSA methodologies, codes and guidelines
- Likely to result in further uncertainty.
- This is an untested methodology.
- Fiduciary responsibilities of entities are likely to be severely impacted.
- Fatal flaws have not been addressed
- The methodology is incomplete, and allowance needs to be made for finalisation before implementation (if possible)
- Potential risk for under- recovery of efficient generation costs.
- Misunderstanding on the impact on changes in sales from forecasts
- Oversimplification of production planning process.
- Misunderstanding on principles of regulating revenue.
- Convolution of many processes.
- Misunderstanding of the power system dynamics.
- Existing contracts may be at risk.
- Information gaps may be a challenge.
- Dependence on smart meters and supporting data management systems may not materalise easily.
- Allowance for proposed tariffs being based on competitiveness, profitability and affordability resulting in subsidies outside of policy.
- Lack of adequate skills and capacity in NERSA have been acknowledged.
- Severe impacts on certain customer segments that has not been examined.

- Inability by stakeholders to understand the process being followed

1.7 Licensee revenue determination ensures recovery of only efficient costs

The only way that it is possible for a regulator to know that their tariff determination adheres to the requirements of ERA s.15(1)(a) and (b), is to calculate the amount of the total prudent and efficient costs, for an assumed level of electricity sales and fair return. Therefore, NERSA will have to determine the total required revenue for the licensed entity. Revenue requirement determination is essential for ensuring financial sustainability for the licensees. Revenue reflects the efficient and prudent costs related to both the fixed and variable costs. Thus, when any changes in volumes of electricity materialises, it is likely that the corresponding variable costs will also vary. This invariably happens. Thus, the utilities' revenue, like any business cannot be guaranteed. It is to be noted that a regulated entity is bound by a NERSA decision. The Board of the entity does not have an opportunity to make its own decisions on how to price its product. It is rather directly linked to the level of prudent and efficient costs, which ultimately is a NERSA decision. This misconception by NERSA that Eskom is asking for a guaranteed revenue needs to dispelled.

1.8 Separation of costs from tariffs

There is a clear indication of the separation of costs from tariffs. These are two very different concepts and cannot be merged and used as proxies. This is a world-wide phenomenon and has been utilised by regulators of the electricity industry. In addition, all efficient costs would need to be considered. Assumptions cannot be made on particular generating technologies supplying particular customers.

1.9 Migrating towards cost reflectivity must be considered

Recognition needs to be given to Eskom's revenue not being at a level where efficient costs and a fair return are recovered. This obviously implies that whatever the methodology is, if what is being referred to as objective costs, are recovered they will be significantly higher than presently. This will also contribute to the adverse effects of a big bang approach. The continual migration towards cost reflectivity will allow this level of flexibility.

1.10 Timeous decision-making is challenging, not methodologies

Eskom humbly submits that further significant progress can easily be made if timeous decisions within the current methodologies are made after due process is followed. NERSA already has powerful frameworks in place that could be applied to address many relevant and viable concepts that are alluded to in the consultation paper. It again needs to be cautioned that all decisions have impacts that need to be considered. This also implies that timeous decision making is required. It goes without saying that due processes need to be followed.

1.11 Mix of market or normal business proposals – does not work

In certain parts of the consultation paper assumptions are being made that a market for generating capacity is in existence. This is not the case. It is argued that a price determination methodology cannot suddenly require a market to be implemented.

It is evident that this consultation paper is comparing electricity licensees to ordinary non-regulated competitive commercial business. This is not a fair comparison, since electricity licensees are monopolies and therefore regulated and are required like NERSA (per ERA) to implement Government policies. It is acknowledged that licensees should apply commercial principles to the best of their ability. However, a blanket comparison cannot be made.

1.12 NERSA will evaluate competitiveness, profitability and affordability

This consultation paper is completely moving away from ensuring that the licensees must recover efficient costs and a fair return, as legislatively required. The implementation will be on the affordability, competitiveness and profitability of customers without considering the sustainability of the electricity supply industry. These will be determined by NERSA. It is assumed that a complete backward movement will be implemented where all customers will be subsidised by the taxpayer.

1.13 Impact of sales volumes

It is important to understand that Eskom provides a forecast based mainly of information provided to it by customers, and that there is no direct consequence to a customer that does not meet its forecast. It has been clarified by Eskom that a need exists for the determination of a revenue requirement. It has also been established that the sales forecast, as determined by NERSA, will also need to be considered. This is a common approach used by many regulators across the world. Without knowing the sales, and from this the expected revenue flows, makes it impossible to forecast production planning, financials and cash flows which are the cornerstone for engagements with key stakeholders including the management, the board, auditors, lenders, rating agencies, labour and government.

"*NERSA concern on sales volume variance is misplaced*" (Prof Eberhard – NERSA Consultation workshop, 18 October 2021). Eskom has demonstrated on many occasions that neither Eskom nor Municipalities have control over sales volumes, and both rely on customer information to develop such a forecast. Eskom undertakes a detailed process to determine the projected sales but relies in the majority on customers to provide this information.

Sales volumes have to be forecast and the actual results are an outcome of a myriad of economic factors such as GDP growth, investor confidence, commodity cycles, disinvestment, de-industrialization, etc. Hence any revenue determination methodology is in line with any globally accepted sound economic regulatory practice, is not silent on sales volumes but factors it into the revenue and tariff equation as an essentially uncontrollable (to the utility) variable. Tariff charges are also derived from the sales volumes, that is, allocated costs divided by a volume (kWh, R/kVA etc.) to get to a charge. Without this forecast a charge cannot be calculated.

As sales volumes increase or decrease, there would be a concomitant increase or decrease in variable costs, but not necessarily fixed costs. The key variable costs for the electricity industry are related to primary energy costs.

NERSA has established that Eskom's fixed costs are at least 65%. Thus, whatever the sales volume, the fixed costs would need to be recovered. Thus, when sales are lower than NERSA originally determined, it is only the fixed costs that are recovered at an RCA stage. It is not additional revenue. Even in a market situation, or for IPP contracts, the fixed costs for generators will be recovered, whatever the volume of energy. Presently, the ROA for IPP contracts is envisaged to be much higher than the 1.08% determined by NERSA for Eskom assets.

Even compared to the cost-reflective price, there are no cheaper unsubsidised international substitutes and alternatives. Furthermore, Eskom's cost-reflective average price is well below the full cost of equivalent (thus, including back-up and storage) South African substitutes and alternatives. Thus, although some price elasticity of electricity demand obviously exists, regarding demand from Eskom it is 'relatively inelastic' at below -0.3 on average. Whereas it requires a price elasticity of demand of greater than -1.2 to trigger the onset of an electricity utility financial death spiral. A volume reduction of 23.3% would be required to neutralise the financial gain from an assumed 20% increase in the average price. This would be equivalent to about 45 TWh for the year.   The average annual reduction in Eskom sales volume over the last decade has been about 2 TWh.

At a tariff level, Eskom's Retail Tariff Plan (RTP) proposal for a generation capacity charge and higher fixed network charges addresses paying for services when consumption is reduced due to own generation, but the grid is still needed.

1.14 Purpose of a regulatory clearing account (RCA)

A final allowable revenue determination is made after the RCA determination. A prudency assessment is undertaken by NERSA prior to this determination. It is further clarified that to make the first decision at the revenue determination stage, it would be based on assumptions at that stage. The actual that manifests after the RCA determination represents the final allowable revenue. It also needs to be noted that when NERSA makes its original revenue decision, it is based on an assumed sales volume. Thus, the fixed costs are recovered from the level of sales assumed at that stage. If the actual sales volume turns out to be higher or lower, then adjustments are made through the RCA. The variable costs will be aligned to the higher or lower sales volume. An alternate way of interpreting this that either Eskom provides an initial subsidy (if the original sales are higher) or the consumer provides a subsidy (if the original sales are lower). Thus, it is a matter of timing – not additional revenue. Thus, no guaranteed revenue.

This proposed methodology seems to have minimised the concept of the regulatory clearing account (RCA). It is understood that the implementation of the RCA does not result in additional revenue being awarded to any licensee. It is only a result of a deferment of the recovery of allowable revenue. The RCA allows for a risk management process to allow for the management of various changes in the environment. In the recent past, Eskom has provided a subsidy to all customers by only being able to recover the RCA balance determined by NERSA at an average of four years after the efficient costs were incurred. In the event that this subsidy was not provided when the revenue decision was made, then all customers will be required to pay a higher initial price.

1.15 Information provided by System Operator

The system operator dispatches in accordance with NERSA's Scheduling and Dispatch rules. This is in accordance with the merit order. It needs to be clarified that the merit order is defined by the variable costs and not the net cost of electricity. It is thus very likely that a generator with the lowest marginal cost (variable) has the highest net cost.

The expectation that the System Operator will capture which generator supplied what amount of power and record the duration of supply is unrealistic. The System Operator will call up power plants in merit order to meet the different loads as they come onto the system and record which generators delivered power and how much over the 24-hour period.

1.16 Application of required sequential processes

It is submitted that many of the ideas and concepts that this consultation wishes to implement are wrongly placed. This results in impossible requirements for the whole industry. It is proposed that the existing framework, appropriately applied could provide the envisaged outcomes. Eskom has previously provided clear guidance on the existing processes that can easily be utilised to allow for further progress.

The sequential process which is already applied is: -

(i) **First**, the determination of the efficient costs and a fair return for the utility resulting in allowed revenue

(ii) **Second**, allocation of allowed costs through a cost-to-serve study

(iii) **Thirdly**, flowing from cost allocation, tariff design

It needs to be cautioned that each of these three steps are complex and require various considerations, especially in accordance with already existing policy, legislation and regulatory rules and codes.

1.17 Validity of continuing with present methodologies

i. Replacement of several existing NERSA methodologies

This proposed methodology seems to seek to replace many NERSA methodologies. These could possibly include the multi-year price determination (MYPD) methodology, the cost to serve (CTS) framework, Eskom Retail tariff and Structural adjustment (ERTSA) methodology and guidelines for Municipal Benchmarks.

ii. Existing NERSA methodologies can achieve key objectives

It has been demonstrated that key implementable objectives of this proposed methodology can easily be implemented by existing methodologies and processes. These include the multi-year price determination (MYPD) methodology, the cost to serve (CTS) framework and Eskom Retail tariff and Structural adjustment (ERTSA) methodology. In addition, the retail tariff plan (RTP) that Eskom had submitted to NERSA during August 2020 together with the proposed update (submitted to NERSA on 5 August 2022), provides specific provisions for further achievement of key implementable objectives. The enforcement by NERSA of the CTS to be used for tariff design for municipal licensees will significantly contribute to cost-reflective tariffs and meeting the implementable objectives. This allows for Municipalities to recover efficient and prudent costs and a fair return.

iii. NERSA continues to determine revenue and tariffs

- Revenue determination by MYPD - The determination of revenue empowers NERSA to only allow efficient and prudent costs. This will be dependent on the availability of Eskom and IPP generation plants. Customers wish NERSA to play a more meaningful role in this aspect. NERSA has a powerful role to play in ensuring in only efficient and prudent costs. The RCA process is an inherent part of the determination of the efficient and prudent costs.
- Apportionment of revenue among customers by CTS - Once the revenue is determined, the CTS will allocate in accordance with services to be provided to with distinctions made between customer-, demand- and energy-related costs classes. Guidance is provided to licensees, who submit to NERSA to approve
- Determination of tariffs and rates by ERTSA –_The NERSA methodology guides Eskom on the application of price increases to provide rates and tariffs for approval by NERSA.
- Municipal tariffs determination together with CTS studies - Allows Municipalities to recover their efficient and prudent costs and a fair return

iv. Eskom Retail Tariff Plan (RTP) allows timeous implementation of further objectives

The RTP is in compliance with policy, legislation and other NERSA regulatory frameworks. This plan is implementable without need for any further information, meters, billing systems revisions, etc. The impacts of implementation have been defined for all stakeholders to engage with. Provided to customers were models to do comparisons, brochures, presentations, stakeholder engagements etc. The proposals in the Eskom retail tariff plan is a move in the right direction reflecting Eskom's unbundled costs, updating tariffs and tariff structures to be more cost-reflective in structure and responding to changing energy environment. Implementation of these known processes allows for incremental migration towards a market.

v. It is not only a matter of methodology but implementation of methodology

The existing economic regulatory methodologies are globally accepted. They do not expire. And similar methodologies to the MYPD are applied across the world. The challenge that South Africa has been facing is the implementation and interpretation of these methodologies. This has been clarified in the several court outcomes. In addition, not all licensees have been in a position to provide submissions based on revenue including cost of supply studies. Enforcing such submissions will assist NERSA in better implementing its existing methodologies.

vi. Eskom has submitted improvement of MYPD methodology

Eskom has submitted proposals for improvement in the existing MYPD methodology in 2020. These proposals have not been considered by NERSA since then.

vii. Requirements for next few years

In accordance with legislative requirements, any revenue and price determination process take a long time to prepare for and implement. It is imperative for NERSA to encourage Municipalities to base tariffs on allowed costs and submit updated tariffs based on cost of supply studies. This will provide more meaningful input to municipal adjustments that are made. There is a pending court judgement on this matter.

Eskom has submitted a retail tariff plan. This has been consulted on and could be further implemented with effect from 1 April 2024.

The possible sequence is as follows:

- NERSA guides Municipalities on providing cost to serve studies – Ongoing
- NERSA implements aspects of the retail tariff plan in accordance with the latest cost to serve study – by November 2023
- NERSA approves ERTSA for FY 2025 – by Jan/ Feb 2024
- Municipalities make price adjustment applications – March 2024
- Eskom implements – 1 April 2024
- NERSA approves Municipal price adjustments – May 2024
- Municipalities implement 1 July 2024

1.18 Rules of this proposed methodology – not understood and risky for stakeholders

The rules for the proposed methodology, are not supported by Eskom. They are not in compliance with legislation and policy. To the extent understood, they result in significant risks to all stakeholders. The basic tenets of a regulatory methodologies that may overlap with this proposal can be considered.

The sequence of the process to determine the price adjustment to get to tariffs is unclear. NERSA proposes to source information from licensees and customers to determine detailed tariffs. The format of the manner in which this information is to be provided is unknown and yet to be communicated to licensees. The level of detail required for NERSA to determine prudent and efficient costs is scant. It is unclear how NERSA will undertake its prudency and efficiency assessments. Is it necessary to be able to replicate any process that NERSA will follow. This is not at all possible. Eskom has attempted to develop a plausible process to evaluate how this would work, but it was simply not possible.

NERSA proposes to utilise information that it will source from electricity customers to determine their usage patterns and load factor. NERSA will then in addition, determine levels of affordability, profitability and competitiveness to determine the prices. How these two concepts will work together is simply not feasible. The shortfall seems to be subsidised by the fiscus.

Eskom, in accordance with NERSA's scheduling and dispatch rules, dispatch generators on a least marginal cost basis already. It is not clear why NERSA appears to assume otherwise. During marginal cost dispatch, the price for the energy is based on the highest dispatched marginal plant, not each generators' marginal cost. For the government IPPs the price paid is the PPA tariff.

The proposed NERSA approach of allocating the cheapest generation to baseload customers is giving preferential treatment to one customer category over the other, ignoring that at any point in time, it is the mix of generation that is used to supply all the load. The mechanics of doing this seems to be impossible in a retail pricing environment and contrary to reflecting system marginal cost-based approach.

Only one example of the load type approach has been documented, but no evidence can be found that it has ever been implemented. The most important flaw is that "*baseload*" customers do consume power during the peak period, the marginal costs are higher during those periods, and if there is a response by reducing demand, it lowers costs for the system. For further reading on the subject (referred to as a decomposition method) refer to the following document "*Electric Cost Allocation for a New Era: A Manual*" (https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf) drafted for **The Regulatory Assistance Project (RAP) which is an independent, global NGO advancing policy innovation and thought leadership within the energy community**

Load profiles and load factors can change daily and monthly. Many customers including those with baseload generation, are considering wheeling energy or installing own generation, and therefore their load profiles will change. The proposed load types and WAT approaches will impact the viability of wheeling transactions and will greatly disincentive customers to do this as they will move to a more expensive WAT. Eskom believes that the current TOU charges and the proposed move to having a generation capacity charge in its Retail Tariff Plan will achieve the objective of sending the right time-based signals for the cost when electricity is used and provide for standby capacity being charged for when customers lean on the system.

1.19 Impact on residential customers

Residential customers would likely fall into the more expensive NERSA proposed load types as they have the peakiest profile of all customers' categories. This would mean that their tariffs would have to increase. A better alternative would be for NERSA to approve the proposed residential TOU tariff Homeflex, and that over time this tariff is made mandatory for higher consumption residential customers (which is aligned to the EPP). This would ensure that the correct pricing signals are provided to peak usage but would not penalise these customers in all time by putting them into the most expensive load type categories.

1.20 Impacts have not been determined – need to be undertaken

One of the greatest concerns with the proposed methodology is there no analysis of the impacts on Eskom, other licensees and customers has been undertaken by NERSA, nor any tools provided where customers could determine impacts. It is impossible to work out what such impacts would be due to the many questions that remain unanswered.

Eskom's retail tariff plan, submitted for NERSA approval, has provided significant details on the impact on various customers. These impacts were considered when the proposals were being designed. It allowed for coherent decisions to be made to allow for a migratory path.

1.21 Benefit of time-of- use signals

About 80% of Eskom's current sales are on a TOU basis. More than half of that is to municipalities, who do not all offer TOU tariffs to their customers. A better approach would be for NERSA as to propose standard tariff structures including TOU to be migrated towards over time.

Moving away from the concept of time of use (TOU), which is in accordance with the EPP to an apparent "*load type*" appears to be favouring one particular sector to the expense of others. Removing TOU signals in tariffs is not cost-reflective and would have a serious impact on managing the electricity system. The System Operator needs TOU tariffs in the absence of a market and the System Operator requirements have not been understood or considered in the "*type of use*" proposal. The TOU approach is an internationally recognised approach to optimally utilising limited resources. Customers, especially industrial customers have been responding to these signals and manage their productivity in accordance with the benefit of the economy and the system. Eskom has also shown in the Eskom retail tariff plan the alignment of the marginal costs to the TOU signals and why these signals should be retained but updated.

1.22 Transitional arrangements need to be consulted on

In the event that NERSA wishes to implement the proposed methodology transitionally, the details need to be clarified upfront. All stakeholders need to be aware of transitional requirements. These would need to be consulted on. It is still necessary to first have a complete methodology and related regulatory requirements. All stakeholders need to be aware of the transitional arrangements. These cannot be subjectively applied. The entire spectrum of applicability needs to be known prior to implementation.

2 Consultation Processes

2.1 Introduction and Background

Eskom hereby provides initial comments on the National Energy Regulator of South Africa (NERSA) Consultation Paper on the *"ELECTRICITY PRICE DETERMINATION METHODOLOGY (EPDM) RULES"*, as published for public comments on 4 August 2023. It is confirmed that this consultation is yet a further step towards the process to develop a new price determination methodology. Although the title of the consultation paper refers to this being a consultation on rules, it is submitted that this document cannot be considered rules. It is confirmed that several previous processes have occurred since around March 2021, in a bid to develop a new approach to meet NERSA requirements in terms of the Electricity Regulation Act (ERA) and the Electricity Pricing Policy (EPP) with regards to the revenue, price and tariffs of electricity.

2.2 Previous consultation processes

It is understood that the following consultations and processes have occurred:

Date	Description
March 2021	NERSA Strategic workshop to assess the NERSA operating environment.
July 2021	Consultation on "*methodology for the determination of tariffs and prices in the electricity*"
Sept 2021	Consultation on "*principles to determine prices in the electricity supply industry*"
Nov 2021	NERSA wished Eskom to apply these principles for the FY 2023 revenue determination. Due to various factors including the non-implementability and not being within the law, this could not be undertaken by Eskom. Thus, this did not happen and the prevailing methodology was applied, in accordance with a semi-urgent High Court decision in December 2021.

Date	Description
Jan 2022	Approved principles were published on 12 January 2022. These principles were supposed to form the basis of a methodology to be published by August 2022 for all licensees to apply for implementation for FY 2024. However, the publication of the methodology did not take place. A court order required NERSA to apply the prevailing methodology for FY 2024 and FY 2025.
June 2022	NERSA published the Electricity Price Determination Methodology (EPDM) Consultation Paper for stakeholder consultation.
August 2022	Public hearing on EPDM consultation paper
November 2022	NERSA held workshops with industry stakeholders, as well as a webinar.

2.3 Present consultation

Aug 2023 – NERSA is again consulting on the *"EPDM Rules"*

2.4 Future consultations – EPDM Roadmap

The following EPDM roadmap was referenced in the *"Review of Cost of Supply Framework to Develop a New Pricing Methodology for Electricity Distributors in South Africa"*, as published on 4 August 2023.

- **Phase 1**: Development of regulatory report that provides a framework necessary for the development of the EPDM rules. This is envisaged to be concluded in the first quarter of 2023, by the end of June, including the consultation process.
- **Phase 2**: Application of EPDM: Develop tariff/price model and simulate the impact. The process is envisaged to be finalised in the first quarter of 2024, by the beginning of April.
- **Phase 3**: Final stage of setting tariffs and prices. This is planned to be done in March 2026.

It is unclear as to whether this consultation is a delayed consultation of phase 1. This is a bit confusing since this consultation refers to the EPDM rules.

3 Confirmation of what a NERSA methodology should enable

It is understood that any NERSA methodology should provide regulatory rules that need to be followed by NERSA licensees to achieve the desired outcome. At a minimum any methodology should meet the following criteria:

- The methodology should be in accordance with prevailing legislation and policy. The High Court, in its judgement of 10 March 2020 (case number 37296/2018) amongst others, confirms that the legal regime governing electricity prices and tariffs include the ERA and

EPP (which is subordinate to the ERA). The EPP requires that NERSA **has** to develop rules, standards, etc to ensure the implementation of the EPP. It is submitted that such a decision by NERSA will become reviewable, if in contradiction to the legal regime.

- The methodology must be aligned to all other NERSA regulatory requirements and NERSA licenses. It should not create any areas of contradiction. In the response to previous stakeholder comments, NERSA refers to the MYPD methodology not being in compliance with other NERSA regulatory requirements, such as the Grid Code when it was developed. This is not Eskom's understanding. Eskom understands that previously, whenever NERSA developed a new methodology or rules, they have always been in compliance with existing regulatory rules, methodologies and codes. It is submitted that it would be absolute chaos if contradictory requirements are stipulated in a new methodology or rule to those that are already in existence.
- If any existing methodology, rule, code, etc is being replaced by a new methodology or rule, this needs to be clearly stipulated in the consultation. The revocation, of any existing rule, methodology, code, etc needs to be addressed.
- It should be clear and precise on the requirements to be met.
- It should enable the relevant licensees to be in a position to implement the requirements of the methodology.
- It is essential to provide clear timing requirements for the implementation of the methodology
- It is essential to provide clarity on which licensees the methodology is applicable to
- Must be clearly implementable with transparent criteria that are replicable and well understood. Licensees and stakeholders should be able to know the outcome of the application of the methodology. Subjective criteria should be minimised
- The requisite information requirements must be known. The support mechanisms need to be known and implementable
- Reasonable times for consultation on elements of the methodology and related requirements including information and reporting requirements need to be provided in accordance with legislative requirements

It is submitted that this consultation paper on the "*EPDM rules*" does not seem to meet many of these minimum requirements. It is unfortunate that after approximately 30 months, NERSA has not robustly considered the valuable contributions made by various stakeholders. In addition, there is no evidence of how the EPDM Rules have progressed from one publication to the next in anticipation of developing a sound methodology as one would expect. Thus, the need for a repetition of what has already been shared with NERSA previously. This will allow for documentation in the event that the only option available to stakeholders would be following the review processes afforded in the Promotion of Administrative Justice Act (PAJA).

4 This consultation paper does not seem to provide rules or even a methodology

It is evident that after many consultations, NERSA has not arrived at a position where it can provide the EPDM rules or a methodology for the licensees to implement. The process has not evolved positively and in fact seems to have regressed. The present consultation document is still very much at a descriptive stage, where the possible nature of processes is being explored. It is understood that NERSA will have difficulty in this venture. This is possibly due to difficulties being experienced in understanding the power system dynamics and having expectations that cannot be met. The unimplementable nature of these proposals further contributes to this.

5 EPDM seems to be still at concept stage with the same non-viable proposals

NERSA proposed ideas as far back as March 2021. The same ideas are still being pursued despite the clarification to NERSA that this approach is not implementable and will not provide any possible advantage to electricity consumers. This process has been going on for at least 30 months. NERSA itself envisages another 36 months (could be longer – since timelines have not been met thus-far) to possibly have a methodology in place. However, Eskom submits that the direction being proposed by NERSA is not viable.

It is for this reason that Eskom finds itself providing similar input that it has done since 2021. It is a repeat of the same concerns that NERSA does not seem to be receptive to. It is unfortunate that such an impasse has been reached and relevant progress is not being made. In communication with other role-players, it is understood that similar challenges are being experienced by many others.

The proposed methodology for setting the revenue and prices and tariffs for especially the licensed generators is mostly unimplementable. Much of it (including some of the core proposals) is impossible to implement, from a conceptual, principle and theoretical perspective. For example, it is conceptually and physically impossible and theoretically incorrect, to link a particular generator to a particular consumer, for any instant of supply and demand. Electricity flowing into an integrated network is a fungible product. At that instant of supply/demand, one electron is like another electron – in effect each electron loses its 'individuality'. Whereas it might be deemed that a particular generator is supplying a particular consumer, in such case it would be based on contracts, not physical reality. NERSA's proposal is however, based on the argument that the physical reality is that electrons can be traced from a particular supplier to a particular consumer, and that their proposal is an attempt to reflect this 'physical reality' in the regulated tariffs. This is simply incorrect. However, if NERSA were to acknowledge that their proposal is not based on any physical reality but on some attempt at 'economic engineering', it would require it to be properly motivated which would open up their proposal to many sound and compelling counterarguments.

Regarding the parts of NERSA's proposals which might not be conceptually impossible, much of it (including some of the core proposals) would be unimplementable by virtue of the impracticality and the difficulty:

- it would require an immense data collection process, of a scale that would render the process impossible in practice – followed by an immense data processing process which similarly would be of a scale that would render the process impossible in practice;
- in addition, these immense data collection and processing processes would be extremely expensive to conduct (for no benefit, and in fact to the detriment of every key objective of sound economic regulation, as also set out in the Electricity Pricing Policy and the Electricity Regulation Act);
- even after completion of such immense data collection and processing processes (if it were practically possible, which it is not), the data would be out of date, not relevant and not applicable before it can be processed, utilised or applied – in fact this would be the case before completion of the data collection process. Whereas there might be some patterns observable to the total industry data at an aggregated and averaged level, the data at an individual consumer level is constantly dynamic – the recent or older history may well not reflect the patterns for the immediate future or coming year, let alone for the medium- and longer-term future, nor could any consumer be 'forced' to adhere to the patterns of consumption as reflected in the provided data. Hence, even if it were theoretically sound to attempt to classify consumers into these proposed categories so as to reflect the 'type of consumer or load type' (which it is not), those classifications would be out of date, not relevant and not applicable before the first electron is consumed under such pricing model by such consumer, thus defeating the entire object of the exercise;
- the above realities regarding data relevance imply that it would require an immense 'real time' process of data collection, processing and application. This would be a process of even greater magnitude and cost. Again, it begs the question why, as there are no apparent benefits but many obvious disadvantages and detriments
- In addition, if there was any inclination or objective in such 'real time' direction, it would be immensely preferable to implement some form of real-time market, and allow real-time market dynamics to automatically do what NERSA is proposing to do in the form of economic regulation – other than, that a market would ensure that the correct economic

signals apply to both the supply and demand sides and would be the basis of decisions on both sides, as opposed to NERSA's proposals that are contrary to the basic fundamentals of economics. This does not imply that the counterproposal is that of a real-time market – as a properly designed economic regulatory system can come very close to reflecting the dynamics of an efficient market (in fact, how close it comes to 'simulating an efficient market' is the overall test of any sound economic regulatory system). However, NERSA's proposals would fail any test for sound economic regulation, including how closely it simulates the dynamics of an efficient market;

- furthermore, such a process of data collection, processing and utilisation would be extremely vulnerable to unmonitorable manipulation by both the data providers or electricity consumers as well as by the data processors, with an inherent conflict of interest and inherent bias from the electricity consumers' side, whilst simultaneously being utterly vulnerable to errors and manipulation regarding the processing and utilisation or application of such data, in an unmonitorable manner thus without it being possible to apply practical checks-and-balances.
- There are sound reasons why this approach is not seen anywhere else in the world – and the above explains why.

6 Working backwards from tariffs is not viable

NERSA seems to require revenue applications to be made at "*Activity*" level. This brings into question whether NERSA is implementing the ERA requirement – NERSA **must** enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return. NERSA refers to EPDM principles where each activity will have its individual tariff; a model (yet to be shared with stakeholders) will transform the permissible revenue into a tariff – where the tariff will allow for collection of the permissible revenue at the time (working backwards); operating capacities is central (not sales or revenue). It is also not clear how the tariffs "*set*" by NERSA will be converted into tariffs to be "*approved*" by NERSA for implementation by licensees.

As will be discussed in the sales section, it has been established that the level of sales has to be a driving force in determining the revenue requirement. It is unclear how a revenue requirement for an "*activity*" can be determined without planning for sales.

All recognised regulatory regimes require ensuring the recovery of revenue requirement through tariffs. Thus, it is essential for the revenue requirement to be holistically determined first before the tariffs can be determined. The process proposed by NERSA, which also considers the affordability, profitability and competitiveness of information provided by customers (discussed in separate section) further complicates matters. Thus, it is not possible that this backward process (if even implementable) allows NERSA to undertake its mandated role.

7 Stakeholder comments have not been considered

Various stakeholders including Eskom have provided many alternative proposals and have been critical of the NERSA proposals in the previous consultation papers. Many stakeholders have significant experience in economic regulation and have provided meaningful contributions. It is submitted that a majority of the contributions made have been completely ignored and responses by NERSA to these contributions are inadequate. It is felt that for the healthy development of a new approach to determining the price of electricity, NERSA is obligated to provide detailed facts, evidence and experience as to why the proposals being made by stakeholders are incorrect. Conversely, NERSA is obligated to provide facts, evidence and experience on how the proposals being made are viable, implementable and meeting the NERSA mandate in accordance with the Electricity Regulation Act (ERA) and Electricity pricing policy (EPP). NERSA has also failed to provide any evidence or facts as to where in the world this proposed approach has been successfully implemented. Unfortunately, it is evident that no progress has been made in developing a viable and implementable methodology since March 2021. It seems that NERSA has decided on certain concepts and are not open to revisiting them, even though no basis for these concepts application can be found or have been proven. It is submitted that a response by NERSA of a contribution stating, "*the stakeholder is entitled to their opinion*", to experienced representatives of the industry is counterproductive to the spirit of consultation to work towards a meaningful, viable and implementable solution for the electricity industry. The constructive criticisms and meaningful inputs provided by stakeholders seems to have fallen on 'deaf ears' and the true benefits of consultations is not felt.

8 Fundamental flaws have been highlighted – however only terminology addressed

NERSA has stated that the challenge is the terminology. The statement made is: "*During the public consultation process, it became apparent, that it was necessary to revise the use of terminology and clarify how the pricing principles would be used in the new pricing methodology.*"

It is unfortunate that NERSA has not addressed the fundamental flaws that have been raised by the majority of the stakeholders and reduced this to a 'mere challenge of terminology' which is a misrepresentation of the facts. This would have allowed for further engagement for all parties to contribute. The details of the fundamental flaws will be shared later in this response document. Many of the definitions now included are not generic (Eskom specific) and are not actually used in the document.

9 Unclear on which methodologies and frameworks are being replaced

NERSA has still not clarified this previous request from Eskom and other stakeholders. Thus, the request is again repeated in this round of consultation on the "*EPDM rules*".

It is understood that NERSA as an administrative body undertook administrative decisions to approve various methodologies and rules. These include the MYPD methodology, the ERTSA methodology, the cost of supply framework, the Distribution Code and the scheduling and dispatch rules. In the various NERSA reasons for decision, NERSA provides a legal basis in support of their decisions. It is thus understood that the decision and the legal basis is binding on NERSA, as the public body. It is understood that NERSA cannot suddenly replace an existing methodology with a new methodology without being explicit about the changes being made. If NERSA wants to replace a methodology, for example the MYPD (a decision it took to approve the document), it must go to the High Court and revoke its decision. It would be in order to make amendments to methodologies once the proper consultation processes have been followed. It is questionable, from a legal point of view, whether NERSA is following the correct process by developing a new methodology without reference to existing methodology/s it is replacing. This could create significant confusion to various stakeholders. Thus is NERSA changing its own decision without following due process. NERSA needs to clarify the status of relevant methodologies, frameworks and rules that this EPDM rule is replacing. It goes without saying, that the reasoning for this needs to be provided as well.

It seems that this methodology/rule being consulted on, is replacing many NERSA methodologies. Up to now, with regards to Eskom, NERSA required the determination of allowable revenue (efficient cost + fair return) by the MYPD methodology. The revenue is then apportioned to customers in accordance with the NERSA cost to serve framework. The revenue is then translated into various tariffs by the use of the NERSA ERTSA methodology. These approvals determined the prices and price adjustments for various prices including prices to be charged by Eskom to Municipalities. NERSA then made further approvals for the prices to be charged by Municipalities to their customers, using a benchmark approach.

In this consultation paper, NERSA has still not indicated the review of the related regulatory requirements. Stakeholders have requested this clarification several time previously. Elements of the extended framework that have a high likelihood of needing revision to align to a new methodology include:

- Cost of Supply Framework for Licensed Electricity Distributors in South Africa (currently also being consulted on by NERSA)
- South African Grid Code and the South African Distribution Code
- Minimum Information Requirements for Tariff Applications (MIRTA)
- Regulatory Reporting Manual (RRM)
- Prudency Guidelines
- Small-Scale Embedded Generation (SSEG) tariffs
- Eskom Retail Tariff and Structural Adjustment Methodology (ERTSA)
- The Distribution Tariff code
- Municipal tariff benchmarking and guidelines
- Licenses awarded by NERSA

All licensees are bound by the requirements of the respective methodologies and codes, and these would have to be revised first before any NERSA approved methodology is published and be applicable. It is envisaged that certain requirements would need to be changed to meet the revised methodology.

10 Unclear on timing requirements for implementation of methodology

As indicated in the consultation on the review of cost to supply framework (dated 4 August 2023) and in the Municipal benchmark consultation (dated 4 April 2023) that the targeted date for the finalisation of this methodology is March 2026. There have been noticeable delays in the previous steps, thus this is likely to be later than March 2026.

It is thus surmised that the prevailing methodologies will be applicable for the foreseeable future. It is acknowledged that NERSA is in the process of reviewing the NERSA cost of supply framework. The reasons for the review are lessons learnt from implementation of the 2016 version, gaps that have been identified and court challenges.

No indication is provided in the consultation paper on the implementation of the methodology. It is implied that further details need to be provided for NERSA to consult on. Indications are that NERSA wishes to finalise an implementable methodology together with related regulatory requirements by November 2023. It is clear that this will not be possible. This also contradicts timeframe referred to in related NERSA documents. The reasons for this have been provided in many other areas of this response document.

11 Key risks related to what is being proposed

Some of the key risks that have been identified include the following

- **Decision-making centralised within NERSA.** Indications are that the entire decision-making process for tariff setting (and approval) is now positioned within NERSA. Licensees are required to provide information to NERSA. NERSA will undertake its analysis and provide the tariff adjustments that will be applicable to all customers. The process seems to be extremely subjective without transparency on processes to be followed. It is essential for all stakeholders to understand and be able to replicate whatever NERSA will be determining. A question is raised on how NERSA can both set and approve tariffs and how this will be addressed relating to Section 42 of the MFMA.
- **Radical big bang change is proposed**. The viability of such an approach is questionable. It seems to be a radical change from the present processes with insufficient time to allow for an orderly development. This methodology seeks to combine many methodologies and thus results in oversimplification of very complex matters. A case in point that the revenue determination that was undertaken at Eskom level required a detailed methodology. However, the revenue requirement is now referred to in passing. Not enough guidance is given on the requirements and process will be undertaken and how this will be implementable by municipal licensees.
- **Not allowing for incremental changes is a risk.** The present regulatory framework is not being at all considered. It may be a problem of throwing the baby out with the bathwater. Sufficient emphasis has not been put on seeing what could be changed within the existing framework to meet certain objectives.
- **The impending changes in the policy and legislative framework may result in further changes.** Consideration has not been given to the impending change in the ERA and EPP through amendments. It is envisaged that these will be finalised within the next few months. Is it appropriate to introduce a new methodology that may need to be reviewed again? There may even be transitional arrangements for NERSA to implement that would need to align with legislation.
- **Non-compliance with existing legislation** There are numerous areas of the consultation paper that are in non-compliance with existing legislation. Key amongst these is the ensuring that the utilities must recover their efficient costs and a fair return. The areas of possible non-compliance with the existing legislation are referred to in various parts of this response. This could potentially result in Judicial reviews by impacted parties.
- **Focus on customers.** The methodology is explicit on the focus on customers and very detailed customer information. Upon closer analysis this seems to be a particular group of

customers. This is already in violation of the ERA – where a balance needs to be considered and may ignore the cost these customers impose on Eskom. However, NERSA is required to demonstrate that it must ensure recovery of efficient and prudent costs.

- **Non-compliance with Electricity Pricing Policy** There are numerous areas of the consultation paper that are in non-compliance with existing Electricity Pricing Policy. Details are provided within the response document. This could potentially result in Judicial reviews by impacted parties.
- **Non-compliance with NERSA methodologies, codes and guidelines** There are numerous areas of the consultation paper that are in non-compliance with existing NERSA methodologies, codes and guidelines. This could potentially result in reviews by impacted parties.
- **Likely to result in further uncertainty.** It has been a struggle to understand this incoherent consultation on a methodology that will have a crucial impact on the economy of South Africa. Many dependencies that are referred to are unlikely to be easily realised. These include the information from licensees, information from customers, implementation of smart meters, ability of NERSA to deliver timeously, understanding the flow of the process, clarity on what criteria will be applicable, how tariffs will actually be designed at the customer level and ability of licensees to be able to respond appropriately.
- **This is an untested methodology.** It has not been possible to establish where in the world for example, the "*load type*" methodology has been applied. During the consultation process on the principles, NERSA was requested to provide such details. None have been forthcoming. In addition, the move away from determining efficient costs and a fair return for a licensee is also a move away from the still applicable (after a century of implementation) of a cost to serve methodology.
- **NERSA has not responded to feedback provided in consultation on principles.** It is greatly appreciated that NERSA initially consulted on the principles that will guide the development of the methodology. However, it is evident that no significant changes have been made to the original objective outlined in the consultation paper on the principles. The responses provided by various stakeholders were not adequately addressed. This should be done with logical and pragmatic reasoning being provided. However, this has not been done to date.
- **Fiduciary responsibilities of entities are likely to be severely impacted.** Due to the requirements of the relevant legislation not being complied with, enormous risks are likely to be experienced by licensees. The key risk being the securing of the revenue streams of licensed entities who are completely dependent on NERSA decisions. This has severe

impacts on the ability of the entities to perform as going concerns and possible fallout on the economy of the country.

- **Fatal flaws have not been addressed**
  The fatal flaws identified by many stakeholders have not been addressed. Meaningful proposals have been ignored.
- **The methodology is incomplete, and allowance needs to be made for finalisation before implementation.** It is appreciated that NERSA still requires further consultation on various questions being posed in this consultation paper before it can finalise a methodology. There are probably many iterations and clarifications that are required before an implementable methodology is available, if at all. This is in alignment with comments made by many stakeholders during consultation on the principles for the development of a methodology.
- **Potential risk for recovery of efficient generation costs.** It is a recognised principle that Eskom generation investments were made in accordance with the Integrated Resource Plan (IRP). Thus, efficient costs need to be recovered. It is unclear from the proposals being made as to whether this principle will be maintained. It is unclear exactly how generation costs will be addressed and how the "*WAT*" tariffs being based on customer load profiles will be able to ensure such revenue recovery. Many Eskom power stations are reaching the end of their lives, and significant decommissioning costs will be required.
- **Non-consideration of sales forecasts.** All licensees use sales forecasts as the basis of their planning processes and to determine tariff charges. This is an accepted regulatory approach world-wide. This needs to be recognised by the regulatory determinations that are made**.** The link to the risk on the stability and ability to continue as a going concern is significant. The determined tariffs must be able to collect sufficient revenue to cover efficient costs and a fair return
- **Misunderstanding on the impact on changes in sales from forecasts**
  The consultation paper seems to have decided to move away from the concept of sales forecasting based on particular understandings that may not be correct. The dependency of sales volumes on the economic developments and changes in the country do not seem to be recognised
- **Oversimplification of production planning process.** It is unclear how the regulatory process will be aligned with the production planning process of Eskom. It is a key determinant of the revenue requirement. It also guides on the resources, especially primary energy to be sourced.
- **Misunderstanding on regulating revenue.** The ERA requires NERSA to regulate revenue. However, the consultation paper refers to complications related to that

requirement in the ERA. It is clarified that revenue is nothing more than efficient costs + a fair return. In most jurisdictions, focus is on analysing utilities' costs to ensure efficient and prudent costs are allowed to be recovered. This would automatically ensure that the customers are benefiting from the prudency criteria have been applied.

- **Convolution of many distinct processes.** The consultation paper seems to mix up various distinct processes in the electricity price determination value chain. This makes it difficult to deal with an already complex system. Thus, implementation will be a challenge. Also, the transition from the present to any further developments needs to be carefully considered.
- **Misunderstanding of the power system dynamics.** The consultation paper makes assumptions it is a new concept that generators should be dispatched on a least-cost basis. Eskom already applies this in compliance to the Dispatch and Scheduling rules and this is nothing new in managing the power system.
- **The proposal on ROA being equal to WACC will likely result in significant price increases.** Eskom has been migrating towards cost reflectivity by tempering the ROA in a gradual manner. This is no longer possible. Likely to have a severe impact on prices.
- **Benchmarks that are not transparent and consulted on, will be impactful.** A need to implement the requirements of the ERA with reference to actual and projected efficient costs also need to be considered. Benchmarks could be applicable as part of the analysis for comparison purposes. It is not easy to localise benchmarks. Will need to consider the environment including financial, technical and legal requirements.
- **Existing contracts may be at risk.** The present contractual conditions that licensees are committed to need to be respected. These include contracts related to NPAs, coal, IPPs, imports and exports.
- **Information gaps may be a challenge.** Any decision will be dependent on integrity of information. It may be challenge with the differing level and high degree of information to be provided to NERSA.
- **Dependence on smart meters and supporting data management systems may not materalise easily.** It is unclear whether the cost benefit analysis has been undertaken to determine the viability of investment in smart meters and supporting systems
- **Allowance for proposed tariffs being based on competitiveness, profitability and affordability** This implies some sort of subsidy and is introducing tariffs being competitive. The price of electricity is already being subsidised by the taxpayer. There seems to be further uncertain amounts of subsidy being proposed or how competition between different customers will be addressed. This is not within the policy framework.

- **Lack of adequate skills in NERSA have been acknowledged.** The implementation of the complex methodology requires further adequate skills and significant increase in capacitation and resources including systems and people. It is unclear how and who will fund this enormous burden.
- **Severe impacts on certain customer segments.** The consultation paper does not point to any impact assessments to be undertaken on any determinations that would be made. From the high-level approach being proposed, it is likely that certain sectors, especially municipalities and residential customers will be significantly negatively impacted by higher price increases. No examples, analysis or information has been provided by NERSA in this regard to make informed inputs.
- **Discrimination could be inferred.** The possibility of certain customer groupings being seen to be discriminated against is a risk, especially when in Eskom's view this will not be based on system cost. This will likely be seen as non-compliance to the ERA – with relation to non-discrimination and non-cost-reflectivity.
- **Inability to understand the process being followed**
  It is not possible to understand the process of this rule to be followed. The value chain of the process and steps to be followed to determine prices is not understandable.

12 No evidence that approach has been successfully implemented anywhere in the world

In the previous consultations including in July 2022, Eskom and other stakeholders requested that NERSA is urged to provide details on where this proposed methodology has successfully been implemented (if at all), what the successes have been, pitfalls to avoid and what the timeframe for implementation was. Eskom has not been able to ascertain anywhere in the world where "*type of use*" (or 4 load types) tariffs has been implemented or even how this could be translated into customer tariffs. Learnings from countries where this approach has been implemented will meaningfully contribute with making progress for an implementable methodology. This approach has rather been rejected.

Unfortunately, no details as requested has materialised in this consultation paper. As alluded previously, Eskom has made intensive searches for such a methodology. The search has resulted in an attempt at this "*load type*" approach. This was abandoned due to not finding any successful implementation as it does not align to cost-pooling and market principles. It is acknowledged that this approach was documented and referred to as the decomposition method of allocating generation cost with identified fatal flaws. Refer to further to Electric Cost Allocation for a New Era: A Manual, Jim Lazar, Paul Chernick, William Marcus, Mark LeBel, Regulatory Assistance Programme, https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

The basic premise that underpins the "*load type*" principle (i.e. that consumers with a constant demand should not contribute towards the cost of variable capacity) is questionable for the reasons outlined below.

- The ESI is designed to meet all consumers' requirements in a way that recognises the "*portfolio effect*" of aggregated demand (where peaks in demand by certain customers coincide with troughs in demand by others) in a way that minimises the overall cost to all customers. Whilst it is true that i) the unit cost of peaking plants is higher than base load and ii) peak demand coincides with higher consumption by certain categories of customers (households, in particular), peaking capacity is economically more viable than base load in short bursts (rather than having idle base load). Accordingly, in our view, the more expensive peaking capacity is to the benefit of all energy users and all customers should contribute towards the cost of utilising peaking capacity. In our view, load type pricing would fundamentally send an incorrect price signal for consumers that have a constant demand.
- In addition, we believe that complexities of numerous variables (variable demand of individual customers, subjective definitions of load profiles, variable source of supply and fluctuating EAF resulting in a variable cost of supply) would make implementation of load type pricing very difficult, if not impossible, resulting in unintended consequences that would be difficult to manage.
- We believe that the principle of intra-day (and season) subsidisation that stems from "*time of use*" tariffs continues to be appropriate, especially when there are energy deficits, as this incentivises "*good*" customer behaviour / reduced demand during peak hours, albeit that the 1:8 principle may be excessive.

13 Unclear on viability of objectives of this methodology

NERSA wishes to achieve the following objectives by implementing this methodology

- improve competition
- achieve cost efficiency; and
- ensure that costs associated with Activities are prudent and efficient.

It is unclear how these objectives can be met by the proposed methodology (assuming that the methodology is implementable). It is humbly requested whether these objectives are appropriate in accordance with the legal regime and the status of the electricity industry in South Africa. These objectives raise questions on whether NERSA is making proposals within its mandate. Eskom is completely in support of ensuring that only efficient and prudent costs are recovered from customers. However, the approach is incomprehensible. Details on the concerns are provided in various parts of this submission.

14 Proposals need to be accordance with legislative framework

- **Introduction to Legislative Framework**

NERSA acknowledges that changes in the regulatory approach can only occur **within the legislative framework**. It seems that focus of hanging the methodology as a rule in terms of Section 34 of the ERA is the be all and end all of the legislative compliance. This is a much trickier situation than made out by NERSA in this consultation paper.

However, confusion seems to have been created on the legislative framework. Certain regulatory proposals are made that contradict the requirements the existing Electricity Regulation Act (ERA), the existing Electricity Pricing Policy (EPP) or other NERSA codes and regulatory frameworks. In addition, NERSA, in this consultation paper, often confuses its approach to the need for legislative changes that are required prior to any regulatory proposals being implementable. Key among these are the proposed amendments to the Electricity Regulation Act (ERA) and Electricity Pricing Policy (EPP). In addition, the National Energy Regulator Act (NERA) and Promotion of Access to Justice Act (PAJA) guides NERSA in the process towards making any decision.

A public body can only exercise the powers conferred on it. It is understood that NERSA cannot develop a methodology based on new activities that are not contained in law. The ERA (current applicable law) does not provide for Consumer groups, Prosumers, Independent System Operator, Central Purchasing Agency, Market Operator, Distribution Wires etc.

It is understood that NERSA has to act in the public interest. The document seems to be biased towards industrial customers while prejudicing other customers, such as residential customers. NERSA's mandate is to balance the interests of all parties (ERA Sect 2(g)) and not act in favour of a particular customer grouping i.e. industrial customers.

A methodology cannot be developed based on a draft ERA Bill or draft EPP. The current ERA is the applicable law. Once the ERA has been gazetted and the revised EPP published, NERSA may then legally amend the methodology. If the methodology is approved by the Energy Regulator, the Energy Regulator may be challenged in terms of Promotion of Administrative Justice Act (PAJA). In accordance with PAJA Sect 6(2)(a) (i) and (ii)- If administrators make decisions that are not allowed by law, they have acted unlawfully, and their decisions are invalid. In general, without legislative authority, administrators are not authorised to make decisions or take administrative action. Additionally, PAJA Sect 6(2)(f) and (h) requires that administrative action must be reasonable and rational.

- **Electricity Regulation Act**

An extract of the ERA on this matter is:

"A licence condition determined under section 14 relating to the setting or approval of prices, charges and tariffs and the regulation of revenues-

(a) must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;"

The responses provided by Eskom in the previous consultation on the principles, do not seem to have not been addressed. These are legislative and policy requirements that cannot be ignored. These comments are included here again for ease of reference.

Section 7 of the ERA provides the activities that require licensing. System Operator and Market operations are not separate licensable activities under the current legislation. Sect 14(2) of the ERA refers to the methodology to be used for the determination of rates and tariffs which must be imposed by licensees.

Sect 15(1)(a) provides that a licence condition determined under Sect 14 relating to the setting or approval of prices, charges and tariffs and the regulation of revenues must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return. Clarity is sought from NERSA on how it will regulate a non-licensed entity and how a price is determined for non-licensed entities.

Provisions of the Electricity Pricing Policy (EPP) are further cited in the Consultation Paper speaking to cost recovery and the revenue requirement. Importantly, Policy Position 1 of the EPP provides that:

"The revenue requirement for a regulated licensee must be set at a level which covers the full cost of production, including a reasonable risk adjusted margin or return on appropriate asset values."

This is further supported in section 2.2 of the EPP in which:

"In the absence of competition, regulators may select from a range of methodologies to regulate the industry. All these options have some advantages and disadvantages. Regardless of the method of regulation or price formation it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that would allow it to operate as a viable concern now and in the future."

Compared to these clearly articulated principles found in legislation and government policy, we find that NERSA's methodology for price determination is arbitrary, and either redundant to existing provisions of legislation, codes and guidelines, or incompatible with those provisions.

- **Administrative fairness includes legislative prescripts required on parties that implement NERSA decisions**

Licensees are required to comply with various legislative requirements. It is understood that NERSA is au fait with such requirements. This includes the required consultation process in terms of the Government Support Framework Agreement (GSFA) and the Municipal Finance Management Act (MFMA) (discussed below).

In accordance with Sect 3.2 of the GFSA, Eskom consults government on the recovery of such amounts resulting from purchases from Independent Power Producers (IPP's) through its tariff application for such MYPD period. It is envisaged that the GSFA would need to be reviewed (if necessitated) or this methodology will be in compliance with the GSFA requirements imposed by the ERA. This alignment is required before any methodology is required.

- **Municipal Finance Management Act (MFMA) Compliance**

It is necessary for both Eskom and NERSA to comply with the requirements of the Municipal Finance Management Act (MFMA) with regards to the adjustment in the price of electricity. For Eskom, on behalf of the Minister of Public Enterprises, section 42 of the MFMA is required to be complied with. Non- compliance with this requirement is not an option.

Section 42: Price increases of bulk resources for provision of municipal services (applicable to Eskom)

*"(1) If a national or provincial organ of state which supplies water, electricity or any other bulk resource as may be prescribed, to a municipality or municipal entity for the provision of a municipal service, **intends to increase the price** of such resource for the municipality or municipal entity, it must first submit the **proposed amendment to its pricing structure**-*
(a) to its executive authority within the meaning of the Public Finance Management Act; and
(b) to any regulatory agency for approval, if national legislation requires such approval.
(2) The organ of state referred to in subsection (1) must, at least 40 days before making a submission in terms of subsection (1)(a) or (b), request the National Treasury and organised local government to provide written comments on the proposed amendment.
….."

It is unclear from this consultation paper as to whether Eskom (and NERSA) will be able to meet this legislative requirement. It seems that a revenue application for the entity is not required, since a revenue application will not be made by Eskom. Activity level revenue seems to be required. The consultation paper seems to indicate that all relevant licensees will provide NERSA with information and from this tariffs will be set. This information will be used for NERSA to make a price adjustment decision. It is also understood that each customer will have a determination by NERSA that suits its particular situation. There is the further issue that if NERSA sets the tariff, can they then also approve the tariff to customers and how this would be accommodated under Section 42 of the MFMA.

As referred to previously, these aspects of the proposed methodology will require intensive consultation and how this can be accommodated for tariffs applied to municipal licensees and the process they have to follow through their councils.

It is accepted the NERSA will not put Eskom into a position, where it cannot enable the Minister of Public Enterprises to meet his legislative requirements in terms of the MFMA. It is proposed that NERSA will need to take cognisance of this legislative requirement prior to finalising the methodology. The purpose of this requirement needs to be respected and complied with.

- **Distribution Licence requirement cannot be met**

Sect 6.2 of the Eskom Distribution Licence states: *the Licensee shall comply with the <u>revenue determination methodology</u> provided by NERSA in determining its prices and tariffs*. Eskom has been licensed by NERSA and must comply with the Licence conditions. It is unclear how this revenue determination methodology requirement for Eskom is manifested in this particular methodology.

- **Compliance with requirements of National Energy Regulator Act (NERA)**

Sect 33 of the Constitution provides that everyone has the right to administrative action that is lawful, reasonable and procedurally fair. Sect 4(1) of the Promotion of Administrative Justice Act (PAJA) provides that where a decision materially and adversely the public, an administrator, in order to give effect to procedurally fair administrative action must <u>consult</u> affected parties.

According to the National Energy Regulator Act (NERA), the decisions of the Regulator, 'Section 10 – Decisions of Energy Regulator, every decision of the Energy Regulator must be in writing and must be:-

"(a) consistent with the Constitution and all applicable laws;

(b) in the public interest;

(c) within the powers of the Energy Regulator, as set out in this Act, the Electricity Act, the Gas Act and the Petroleum Pipelines Act;

(d) *Taken within a procedurally fair process in which affected persons have the opportunity to submit their views and present relevant facts and evidence to the Energy Regulator;*

(e) *based on reasons, facts and evidence that must be summarised and recorded; and*

(f) *explained clearly as to its factual and legal basis and the reasons therefor."*

It is thus submitted that NERSA is yet to complete this consultation paper with all relevant details as these are yet to be consulted on. Enough detail is not included to allow stakeholders to meaningfully submit views and present relevant facts and evidence.

- **Judge Kollapen Judgement (Case 37296/2018, Judgement dated 10 March 2020)**

The following extract from the judgement is of relevance. *"In the event that NERSA decides to depart from its methodology it first needs to formally revise the methodology, which requires it to consult on this revised methodology."* Since NERSA is revising its prevailing methodologies, a requirement to consult prior to finalisation is necessitated. As has been pointed out in many sections of this consultation paper, various details are yet to be provided for consultation.

- **Viable option for providing end users proper information regarding their costs**

Section 15 (1)(c) of the ERA, requires that tariffs "*must give end users proper information regarding the costs that their consumption imposes on the licensee's business*."

In this consultation paper, NERSA seems to indicate it is attempting to determine the exact costs of each customer's consumption. It is submitted that impossible expectations are being raised. These do not seem to be feasible. If it is at all possible to make such a determination, it would require many assumptions to be made on load profiles, since no independent source of such information is viable. The overall cost benefit analysis for this apparent exactness needs to be considered.

It is submitted that NERSA presently implements this requirement for Eskom customers, through various existing methodologies, frameworks and processes. These include the determination of Eskom's allowable revenue through the MYPD methodology, the allocation of determined revenue based on demand and energy profiles, and then application of NERSA ERTSA methodology to determine tariffs and rates. NERSA also has the opportunity to consider applications by Eskom for unbundling and restructuring tariffs to be better aligned with approved costs and cost-drivers made through the 2020 and 2022 retail tariff plan, albeit these applications were unsuccessful and not approved by NERSA. These existing processes allow for meaningful cost information to be made available to customers.

- **Possible areas of discrimination**

Section 15 (1) (d) of the ERA requires that tariff principles *"must avoid undue discrimination between customer categories"*. Is it possibly conceivable, that NERSA is allowing discrimination of particular customer categories in the process of developing this methodology that would not be aligned with costs or based on any justifiable reasoning. It could be interpreted that certain customers that are large industrial customers are favoured over other customer categories. These sentiments were further cemented by NERSA during workshops held recently with stakeholders.

- **Electricity Pricing Policy**

The prevailing Electricity Pricing Policy – EPP (2008) extensively guides the treatment of all electricity pricing and especially wholesale and retail energy pricing. Therefore, to discuss the proposed methodology, there is a need to engage on these, as set out by the EPP for electricity tariffs including:

- Cost reflectivity: The EPP defines cost reflectivity as "*the pricing method to reflect the full economic cost of supplying electricity to a customer*". Policy position 2 provides that electricity tariffs must be a reflection of efficient costs to render electricity services as accurately as practical.
- Cost of supply studies (CoS): Policy position 23 requires electricity distributors to submit CoS studies at least every five years or in the event of significant changes in customers, relationship between cost components and sales volumes, and to accompany proposals to NERSA for tariff structural changes.
- Customer categories: Policy position 26 directs that the number of customer categories are to be justifiable to NERSA based on cost drivers and customer base (usage times, load factor and average consumption, type of supply/connection equipment, density of location, metering, voltage of supply) and to expand on the categories where costs differ by at least 10% between a group of customers.
- Distribution losses and Bad debt: Policy position 27 informs that NERSA must develop acceptable standards for non-technical losses and provision for bad debt. That the component of non-technical losses and bad debt which exceeds the approved standard must be considered unacceptable and be removed from the approved revenue base.
- Flexibility to package electricity for sale: Policy position 6 allows for the development and introduction of special products and prices to achieve specific goals, the cost of which will be treated to the regulatory methodology.

- Price path: Policy position 7 requires the NERSA after consulting with stakeholders, to develop and publish a multi-year price path on an annual basis.
- Transmission zonal pricing: Transmission geographic differentials for customers must remain until it is succeeded by an approved redefinition of geographic differentials developed by the DMRE and NERSA after considering price stability and comparing the current generation mix to the foreseen in the next 10 years.
- Tariffs with cost reflective tariff charges: Policy position 27 requires NERSA by 2013 to have ensured that cost reflective tariffs reflect energy costs in c/kWh; network demand charges in R/kVA/period; network capacity charges in R/kVA/month, customer service charges in R/cust/month, point of supply costs R/POS/month; and cost for poor power factor.
- Time of use (ToU) tariffs: Policy position 31 requires that ToU tariffs are encouraged actively recognising customer load profiles differ significantly and directs that tariff must include TOU energy rates phased over 2 years for customers supplied at MV and above, 5 years for 100kVA all customers with the metering capability and for all other customers where it is warranted.
- Voltage differentiated network tariffs: Policy position 35 requires that voltage and supply position differentials must be applied in tariffs within a licensed distributor. This would be based on supply and system voltage, cost differences as captured in the cost of supply study, provided as different energy and demand/capacity charges not as a percentage on all charges. Further, the NERSA must create a plan for phased increases to tariffs at lower voltages and increases to those at higher voltages.
- Tariff subsidies: Policy position 44 instructs that the application of only specifically approved cross-subsidies, subsidies, levies, and surcharges must be instituted in the electricity supply industry to address certain socio / political/environment needs. Cross-subsidies should have a minimal impact on price of electricity to consumers in the productive sectors of the economy.
- Definitions: Cost-reflectivity - The pricing method to reflect the full economic cost of supplying electricity to a customer;
- par.5.2 / Policy Position 12 "…. *pricing structures need to encourage the efficient use of electricity at all times* ….";
- par. 8 "….. *key principle for distribution pricing, namely that tariffs would be cost reflective and are in support of cost reflectivity*…..";
- Policy Position 30: "*Cost reflective tariffs are considered the most effective pricing signal to be provided to customers*";
- par.10.1: "*Whenever deviations from cost are applied …. the economic signal would be distorted which could in turn lead to inefficient allocation of resources in the economy*".

- Policy Position 56: *"(a) Cost reflective tariff levels and structures as discussed in the EPP shall be the first main driver of DSM and efficient use in the ESI. For this reason unbundled cost reflective charges must be charged to customers. (b) This is to be applied as one of the NERSA tariff evaluation criteria*";
- par 12 'Conclusions': "*The underlying approach in the development of the various policy positions is to promote economic efficiency*".

The Distribution Codes states the following:

4.1.1 Tariffs should recover current regulated revenue requirement but may reflect future cost drivers in their structure to provide clear pricing signals to the customer, that promote economic efficiency.

4.1.5 Cost pooling (aggregation and averaging of costs) is required due to practical reasons.

4.2.1.4 Tariff charges (including energy costs) will not be based on customer specific assets or services, but aggregated and averaged based on justifiable pooled costs.

4.2.1.5 The components that make up a tariff structure will be aggregated and averaged to a lesser or greater degree depending on the tariff category being served.

7.1 Tariff structures should reflect cost drivers as far as possible. Where tariffs structures do not reflect costs, there is risk associated with mismatching of costs, tariff conversions and changes in volume forecast. The distributor/service provider shall be allowed to mitigate this risk, through appropriate tariff or claw-back mechanisms (for both under or over recovery of revenue) within the revenue requirement.

7.2 The tariff charges (rates) shall be calculated based on the approved revenue requirement, volume forecast for demand and energy and customer numbers. At the end of each revenue review period, the NERSA may audit and verify the tariff charges (rates) calculations and results.

This Consultation Paper is in contradiction with the existing Distribution Tariff Code. These include concepts introduced in this Consultation Paper that have never been encountered previously, anywhere in the world, such as load type.

15 Proposed Customer Focus

The entire focus of this consultation paper is echoed by the following statements:

"Implementing a more balance customer focused approach may seem profound or even counter intuitive after one and a half decades of MYPDM, however, it is an overdue correction in the role of the Regulator in stabilising the electricity industry."

However, the objects of the ERA include the following:

- *"To achieve the efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure in South Africa;*
- *To ensure that the interests and needs of present and future electricity customers and end users are safeguarded and met, having regard to the governance, efficiency, effectiveness and long-term sustainability of the electricity supply industry within the broader context of economic energy regulation in the Republic; and*
- *To facilitate investment in the electricity supply industry; and to facilitate a fair balance between the interests of customers and end users, licensees, investors in the electricity supply industry and the public."*

Thus, it is argued that having only a consumer-focused approach is not what is enshrined in the objects of the ERA. It is submitted that having such a one-sided approach is more likely to harm the consumers that this consultation paper is attempting to focus on. The ERA objective is to ensure the long-term sustainability of the electricity **supply** industry.

(b) In addition, the ERA requires that the Regulator *"**must** enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return"*

It is thus summarised that licensees and NERSA must operate within the legislative and policy framework. Similar responses were provided during previous consultations (during 2021 and 2022). It is thus urged that the required attention be given to this compliance. It is unfortunate that NERSA has not attempted to ensure that it is compliant with the relevant legislative and policy requirements.

The NERSA regulatory framework currently includes licences, codes, methodologies and rules. These have all been approved by NERSA Board and have followed the appropriate consultation and governance processes. Thus, it would be necessary to ensure alignment with all existing NERSA legal instruments before the outcome of this consultation paper is employed for the development of a draft methodology for further consultation. In addition, it would be incumbent on NERSA to ensure alignment with the hierarchy of the legal framework to avoid confusion and possibly resulting in negative impacts on the industry.

The extended framework also needs to address legislation that speaks to the administration of the pricing decision (i.e. in addition to the ERA and NERA) inclusive of:

- The Municipal Finance Management Act
- Public Finance Management Act
- Local Government (Municipal Systems) Act (2000) ("Systems Act")
- Municipal Fiscal Powers and Functions Act (2007) ("MFPFA")

It is quite conceivable that certain provisions of legislation may limit the scope of mooted revisions to the pricing methodology unless amended. This aspect of the review by itself will require significant attention in implementation.

16 Conflict with other legislative mandates

The South African Bureau of Standards (SABS) is mandated by the Standards Act to issue Standards for the country. It is the only body that may issue standards for the country and all entities in South Africa are required to adhere to those standards. SABS has issued a metering standard. The data required in the Consultation Paper is likely not provided for in the metering standard therefore there is no obligation on service providers to collect the information. It is thus incumbent upon NERSA to ensure alignment with such existing legal requirements. This is the only way to ensure order in the development of any new methodology that it is envisaged that this Consultation Paper will result in, once the responses have been received from stakeholders.

17 NERSA decisions based on NERSA opinions

- In best interest of Electricity Industry, overall South African economy and the public

This seems to be a wide- sweeping statement that likely goes well beyond the mandate of NERSA in terms of the ERA and EPP. It is submitted that NERSA cannot base decisions on opinions. It is hoped that this approach is revisited. As discussed earlier, the mandate of what NERSA <u>must do</u> and what it <u>may do</u> – is very clear. This creates uncertainty and will result in many stakeholders being aggrieved. NERSA is cautioned from continuing on this path.

18 Correction - MYPD is a methodology with legal status

The following statement made in this consultation paper is of concern:

"In the past, the MYPD was a methodology with no~~(t)~~ legal status, beyond the precedent set by its usage"

This is simply not true. It is submitted that NERSA is required to correct this incorrect fact. This is in violation of a NERSA approved methodology, has been deposed by NERSA in several affidavits including a recent one referred to below and has been confirmed by an extract from a recent High Court judgement.

This is supported by the following extract from the NERSA methodology and included in all NERSA decisions made in accordance with the MYPD methodology.

The extract from the NERSA MYPD methodology, as published in 2016, on the legal basis of the MYPD methodology is extracted here:

"*3 Legal Basis*

3.1 The legal basis for the MYPD Methodology is provided in the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the Act'). Section 4(a)(ii) of the Act states that 'the Regulator must regulate prices and tariffs'. Further, section 15(1) and (2) of the Act prescribes the following tariff principles:

(1) A license condition determined under section 14 relating to setting or approval of prices, charges and tariffs and the regulation of revenues –

a) Must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;

b) Must provide for or prescribe incentives for the continued improvement of the technical and economic efficiency with which the services are to be provided;

c) Must give end users proper information regarding the costs that their consumption imposes on the licensee's business;

d) Must avoid undue discrimination between customer categories; and may permit the cross subsidy of tariffs to certain classes of customers.

(2) A licensee may not charge a customer any other tariff and make use of provisions in agreements other than that determined or approved by the Regulator as part of its licensing conditions.

3.2 Including the provisions of section 14(1)(e), apart from the Act, the Electricity Pricing Policy (Electricity Pricing Policy GN 1398 of 19 December 2008) ('EPP') gives broad guidelines to the Energy Regulator in approving prices and tariffs for the electricity supply industry."

The legal basis for the MYPD methodology was referred to by NERSA, in its answering affidavit to the review application made by the Democratic Alliance and others (Case number 2023-003615) as deposed by Mr Gumede during February 2023. The affidavit, in paragraph 42 clarifies the following: "*The legal basis for the methodology (referring to the MYPD methodology) is is provided in section 4 (a) (ii) of the ERA which, as indicated earlier states* *that the "Regulator must regulate prices and tariffs*". *It is also rooted in section 15(1) and (2) of the ERA which prescribed tariff principles."*

This legal basis has been further ratified by the following extract is from a High Court Judgement (CASE NO 51550/2021) related to the processing of Eskom MYPD 5 revenue application for FY 2022/23 as handed down in December 2021.

"Legal basis
3.1 The legal basis for the MYPD Methodology is provided in the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the Act'). Section 4(a)(ii) of the Act states that 'the Regulator must regulate prices and tariffs'. Further, section 15(1)and (2) of the Act prescribes the following tariff principles:
(1) A license condition determined under section 14 relating to setting or approval of prices, charges and tariffs and the regulation of revenues
a) Must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;
b) Must provide for or prescribe incentives for the continued improvement of the technical and economic efficiency with which the services are to be provided;
c) Must give end users proper information regarding the costs that their consumption imposes on the licensee's business;
d) Must avoid undue discrimination between customer categories; and may permit the cross subsidy of tariffs to certain classes of customers."
[12] The methodology is a detailed document of more than 40 pages and provides considerable detail of how a tariff application is to be submitted and the information and the manner in which it is to be submitted. It is complex and covers matters of an operational, technical and financial nature. This methodology, subject to some changes over time, has been the one used since 2006 to the current time which covers the tariff determination for the year 2021/2022.
[13] There is according to NERSA no methodology in place for the period 2022/2023 and the dispute in these proceedings is precisely about that. It is common cause that there needs to be a determination which needs to be tabled in Parliament before 15 March 2022, in accordance with the requirements of section 42(5)(a) of the Local Government (Municipal Finance Management Act)5 ("the MFMA")."

NERSA has always been mandated in terms of the ERA to regulate all licenced entities in the electricity industry in South Africa. One of the focus areas by NERSA has been regulating the Eskom revenue. This is understandable, since the crux of the overall price of electricity will be impacted by the decisions NERSA makes in terms of the MYPD methodology. It is submitted that NERSA has been determining the tariffs for Eskom and Municipalities by the approvals made in terms of the ERTSA methodology and the Municipal guideline increases.

19 EPDM will be rule in terms of S35 of ERA

It is acknowledged that NERSA wishes to finalise this methodology in terms of Section 35 of the ERA (assuming it changes in response to proposals made by stakeholders). However, it is not possible that rules have a status of legislation. It is clarified that Sect 35 provides that the Regulator may make guidelines, publish codes of conduct, or make rules by notice in the Gazette. 'Guidelines, Codes and Rules' are not law. They are subordinate to legislation. The ERA is legislation. If the ERA were to be scrapped, the Guidelines, Codes and Rules approved under the ERA have no legal validity. The focus of Eskom's concern is not on the semantics of the methodology being a rule, but rather on the fundamental legislative and policy aspects of the ERA and EPP being implemented by the mandate that NERSA is afforded.

20 Mix of market or normal business proposals – does not work

In certain parts of the consultation paper assumptions are being made that a market for generating capacity is in existence. This is not the case. It is argued that a price determination methodology cannot suddenly require a market to be implemented. It is confirmed that this is a complex process, and the legislative requirement would need to cater for such a migration to occur. If and when a market does exist, the "*load type*" approach would certainly not apply as the price paid would be the cost of highest dispatched generator in a particular hour.

It is evident that this consultation paper is comparing electricity licensees to ordinary non-regulated competitive commercial business. This is not a fair comparison since electricity licensees are monopolies and therefore regulated and are required like NERSA (per ERA) to implement Government policies. It is acknowledged that licensees should apply commercial principles to the best of their ability. However, a blanket comparison cannot be made.

The risk of the apparent proposals on a market and fully commercialised entities is that the nature of the electricity industry and sub-cost reflective tariffs (for certain licensees) has not been factored in. The possible outcome could be that the generators would not declare themselves available, and the demand in the country will not be met. It should be noted that for fully commercialised entities, there would need to be a significant increase in prices.

Concern is raised on the quote: "a Licensee remains exposed to normal business risks". It would clearly significantly increase a licensee's cost of capital which will require that a licensee then be allowed to earn a much higher return on capital, commensurate with the increased risk. However, any infrastructure investment (e.g. for electricity supply) is and has always been inherently high risk already, given the large amounts of capital, the 'sunk' nature once the investment has been made, the very long period over which an investor must recover the originally invested capital and earn the returns, etc. Hence the emergence of economic regulation as means to reduce the investment risk by essentially 'socialising' it, which approach has been in use for hundreds of years so as to attract capital and facilitate investment, without which an inherently capital-intensive industry (such as the ESI) would not be able to exist. Any increase in investment risk as implied by NERSA's proposals would further disincentive investment of capital into the industry – a crucial matter given that the lack of capital investment is at the core of the country's lack of generating capacity. NERSA's approach will thus imply an additional hurdle to efforts to solve the electricity supply crisis in SA.

21 NERSA will evaluate competitiveness, profitability and affordability

This consultation paper is completely moving away from ensuring that the licensees must recover efficient costs and a fair return, as legislatively required. The implementation will be on the affordability, competitiveness and profitability of customers without considering the sustainability of the electricity supply industry. These will be determined by NERSA. It is assumed that a complete backward movement will be implemented where all customers will be subsidised by the taxpayer. Extensive studies have been undertaken to illustrate that this is not the correct direction to move towards. Eskom, with NERSA has been moving in a direction towards customers paying cost reflective prices. The mechanics of such a proposal is very complex and cannot be undertaken by a regulator. If this was within the legislative framework, then this has a high likelihood of resulting in enormous number of disputes.

22 Regulatory Clearing Account adjustments are essential and beneficial for customers and utilities

This proposed methodology seems to have minimised the concept of the regulatory clearing account (RCA). It is understood that the implementation of the RCA does not result in additional revenue being awarded to any licensee. It is only a result of a deferment of the recovery of allowable revenue. The RCA allows for a risk management process to allow for the management of various changes in the environment. In the recent past, Eskom has provided a subsidy to all customers by only being able to recover the RCA balance determined by NERSA at an average of four years after the efficient costs were incurred. In the event that this subsidy was not provided when the revenue decision was made, then all customers will be required to pay a higher initial price.

The removal of most of the retrospective adjustment mechanisms to deal with changes between forecasted/estimated parameters and actual outcome, especially with regard to matters non-controllable by the licensee, is contradictory to accepted sound economic regulatory practice world-wide. It will have one of two consequences, namely it will force very conservative assumptions to be made (by the licensee as well as the regulator) which will increase prices to the consumers, or it will dramatically increase uncontrollable risk on the licensee – which in turn will either result in significantly increased cost of capital (which must be recovered through revenue as per the ERA, thus again resulting in higher consumer prices), or inability to attract capital to the electricity supply industry. Failure to attract capital to an inherently capital-intensive industry would be a major failure of economic regulation and a breach of one of the objects of the ERA as set out in s.2(c) namely *"The objects of this Act are to - facilitate investment in the electricity supply industry".*

In addition, it appears as if a major motivation for removal of most retrospective adjustment mechanisms is the apparent misunderstanding of the current RCA mechanism as pertains to dealing with sales volume variances – it seems as if the mechanism is (wrongly) assumed to 'guarantee revenue' or to enable a licensee to arbitrarily choose a desired revenue amount and to rely on the RCA to achieve such revenue amount. These apparent misinterpretations of the functioning of especially the RCA's sales-volume adjustment mechanism, instead of understanding it to be a mechanism simply to ensure that fixed cost that had been assessed by the regulator as prudent and efficient, would be recovered – with the RCA mechanism clawing-back any over-recovery, or compensating for any under-recovery of such (assessed and approved by the regulator as prudent and efficient) fixed cost. It is unclear:

a) how the proposed tariff methodology would give effect (on a prospective, forecasted basis) to the requirement for revenue to allow recovery of prudent and efficient costs;

b) how it will be confirmed retrospectively (by any party – NERSA or the licensees) whether the prospectively-determined tariffs actually gave effect to the required revenue or whether it allowed over-recovery or under-recovery of revenue;

c) how much of such over- or under-variation in overall revenue was due to deviations from forecast on matters which are acknowledged to not be controllable by the licensee;

d) how any variance in revenue that was due to acknowledged uncontrollable deviations from forecast would retrospectively be adjusted for.

If these aspects cannot be satisfactorily demonstrated, it is unclear how the methodology would enable NERSA to give effect to the objectives of the Electricity Regulation Act such as "*to achieve the … sustainable development and operation of the ESI in SA; to ensure that that interests and needs of present and future electricity customers and end users are met, having regard to the long-term sustainability of the ESI; to facilitate investment in the ESI*"; etc. It is furthermore unclear how NERSA would be able to confirm that it gives effect to the requirement of the Electricity Regulation Act to allow the full efficient costs related to a licensed activity to be recovered.

23 Sales forecast are necessary for revenue and tariff decisions

It has been clearly clarified that a need exists for the determination of a revenue requirement. This concept can also be referred to as establishing the efficient costs and a fair return. It has also been established that the sales forecast, as determined by NERSA, will also need to be considered. This is a common approach used by many regulators across the world. Without knowing an expected revenue flows makes it impossible to forecast financials and cash flows which are the cornerstone for engagements with key stakeholders including the management, the board, auditors, lenders, rating agencies, labour and government.

The NERSA consultation paper (to borrow from Professor Anton Eberhard's presentation at the NERSA workshop of 18 October 2021) seems to have diagnosed one of the problems as being the regulatory determination of revenue, which (NERSA assumes) then results in loss of sales volume, which (NERSA assumes) then results in clearing account adjustments to recover lost sales), thus 'chasing your tail' as NERSA puts it. This is however not correct.

Firstly, regarding the assumed loss of sales volumes, NERSA seems to assume that it is / was mainly a function of increasing prices. A number of studies by credible independent specialist economists have however shown that the main or dominant drivers of electricity sales volume reduction has **NOT** been Eskom's electricity price but instead has been a function of lack of GDP growth, divestment and de-industrialisation in SA over the last decade, commodity cycles, policy uncertainty etc. Indeed, when Eskom's prices were increasing at 25% per year (thus, around 19% above inflation) prior to FY 2012/13 the annual electricity demand was still growing at 2.7% (FY 2010/11) and 0.2% (FY 2011/12). However, in the subsequent years of MYPD3 when Eskom's tariffs were increasing at around 8% per year (thus, around 2% above inflation) the sales volumes were decreasing at between 0.2% and 0.9% per year. Indeed, for FY 2017/18 when NERSA allowed a nominal price increase of below 2% (thus, a real price decrease of around 4%) the sales volumes decreased by 0.9%, and for FY 2018/19 when

NERSA allowed a nominal price increase of below 6% (in line with inflation thus a nil real increase) the sales volumes decreased by 1.8%.

This of course does not address the situation of municipal prices, which are much higher than Eskom's based on NERSA's annual municipal tariff adjustment process. If there has been any effect of price elasticity of demand it is likely to have been in response to the much higher municipal prices, which however has been set by NERSA.

Secondly, the clearing account adjustments which then followed was not to 'recover lost sales'. Indeed, if such lower volumes had been correctly forecasted or anticipated by Eskom and NERSA there would have been no clearing account adjustments. The adjustments emanated purely because the sales volumes forecasts (as made in 2012 for the five-year MYPD3 cycle) did not correctly anticipate the volume outcome. As such recovery of the fixed cost was based on a higher sales volume thus resulting in a lower rate per kWh for fixed cost. Therefore, the clearing account adjustments were NOT to 'recover lost sales' but purely to recover the under-recovered fixed cost. During every clearing account process Eskom has submitted various papers to explain this. It was also the subject of most of Eskom's applications to the High Court for a judicial review of a NERSA RCA decision, and the High Court confirmed this and found in Eskom's favour on that matter.

Therefore, it seems the entire diagnosis and departure point of NERSA concern with setting of revenue is misplaced and without foundation and that rather focus by NERSA should be to apply the existing methodology to the best of their ability.

Furthermore, the basis of the world-wide approach in sound economic regulatory approach of setting revenue according to the 'cost of service' model is not a 'unique solution' adopted for some reason by regulators – the approach is founded on basic fundamental corporate finance principles. In fact, there can be no other approach in order to achieve long term financial sustainability which is a key and critical basis for attracting the needed capital (debt and equity) in the first place so as to enable the investment in the expensive assets which is characteristic of this asset-intensive electricity industry.

Therefore, the cost elements or cost 'building blocks' must be recovered through revenue in order to be financially sustainable in the long term and to attract the capital in the first place to enable the product to be provided. Thus, the role of revenue is to recover those legitimate and inherent cost elements. There can be no means of assurance that the cost elements are recovered other than that the revenue must be equal to the sum of the main cost elements of fuel cost (primary energy), operating and maintenance cost, depreciation and cost of capital.

If 'revenue' as a concept does not feature in the regulatory methodology, there can be no means of measuring or assuring that the cost elements are recovered.

There is sometimes the idea that the various other common economic regulation approaches such as 'price cap' is not based on revenue. This is however not correct – even for a 'price cap' approach the initial reference price must and is set with regard to the same four conventional main cost elements or 'building blocks' of fuel cost (primary energy), operating and maintenance cost, depreciation and cost of capital.

Setting of revenue is not the main driver of Eskom's sales volumes and does not result in 'chasing your tail'. Nor does retrospective clearing account adjustments for changes in sales volume constitute 'recovering of lost sales' – it is merely a mechanism to recover under-recovered fixed cost, which is one of the four 'cost building blocks' and is required to be recovered for long term financial sustainability and thus critical to enable capital to be attracted to the entire electricity industry.

- As described in Section 1 of the MYPD Methodology,[1] it:

*"was developed for the regulation of Eskom's required revenues. It forms the basis on which the National Energy Regulator (NERSA) will evaluate the price adjustment applications received from Eskom. ,,,,, "It **is a cost-of-service-based** methodology with incentives for cost savings and efficient and prudent procurement and overall operations by the licensee (Eskom)." **(Emphasis added)***

- As a cost-of-service approach to setting Eskom's allowed revenue the MYPD Methodology has as its central focus the revenue required to recover the prudent and efficient cost of supply. This revenue requirement is formalised in the MYPD Methodology in terms the 'Allowable Revenue Formula' which is illustrated below in a highly abridged format.

[1] NERSA, Multi-Year Price Determination (MYPD) Methodology 2016.

Table 1: Build-up of Allowed Revenue

Total cost of service	Return *on* Assets
	Depreciation
	Operating expenses
	Primary Energy
	IPPs
	International Trade
	IDM
	Reseacrh & Development
	Service Quality Incentives
	Levies and Taxes

- Under provisions of the MYPD Methodology:

– Allowed Revenue is built up from forward looking estimates of qualifying costs as described in the MYPD Methodology; and is

– Assessed for prudency following NERSA's Guidelines for Prudency Assessment.

– Revenue and cost adjustment mechanisms reconcile variances in forecast to actual values of inputs to the revenue requirement on an *ex-post* basis.

Average unit price is then calculated such that at deemed forecast sales volumes the revenue allowance is just obtained in expectation. Importantly – this average unit cost is primarily employed in calculating the percentage adjustment to individual elements of a given tariff class, it is not used to derive tariffs. The structure of tariffs is determined under a separate process divorced from revenue determination – which might be carried out at different or roughly parallel timelines (refer to Eskom 2020 retail tariff plan submitted to NERSA which sets out how the tariffs would be derived).

- "*NERSA concern on sales volume variance is misplaced*" (Prof Eberhard – NERSA Consultation workshop, 18 October 2021). Eskom has demonstrated on many occasions that neither Eskom nor Municipalities have control over sales volumes and both rely on customer information to develop such a forecast. Eskom undertakes a detailed process to determine the projected sales. NERSA also undertakes its independent process to project sales.

- Regarding declining sales, analysis indicates that to the degree that customers are opting for self-generation, it is not because of too high Eskom prices but mainly because of inadequate and unreliable supply – which ironically would inevitably result from chronically sub-cost-reflective tariffs, as also Professors David Newbery and Anton Eberhard stated in their report to government. Prof Anton Eberhard's further research confirmed that this is empirically observed in most if not all countries where electricity tariffs are artificially suppressed to chronic sub-cost-reflective levels, and that in addition the consequence is then that consumers in such countries, in effect, experience higher cost of electricity than even the cost-reflective grid price, given that they have no option but to self-generate at extreme costs (per the World Bank).

- If prices are 'too high' to some consumers it will not be Eskom consumers (for which it is becoming more and more acknowledged that the prices are extremely low by any credible benchmark reference) but municipal customers, many of whom pay much higher tariffs to their municipalities, which tariffs are approved by NERSA annually.

- It is obviously inconceivable that the MYPD methodology or NERSA or Eskom or government could 'set' actual sales volumes. This is obviously an outcome of a myriad of economic factors such as GDP growth, investor confidence, commodity cycles, disinvestment, de-industrialization, etc. Hence the MYPD methodology in line with any globally accepted sound economic regulatory practice, is not silent on sales volumes but factors it into the revenue and tariff equation as an essentially uncontrollable (to the utility) variable.

- The tariff needs to be restructured to ensure that cost reflectivity at a tariff level is migrated towards to mitigate volume risk. This is in the hands of NERSA to address through allowing and encouraging the restructuring of tariffs so as to enable recovery of the fixed costs through appropriate fixed charges from all customers that are grid-tied, who will still rely on the grid for back-up. Most of Eskom's sales volume is provided by customer's themselves with no consequence to these customers for incorrect forecasts other than through the RCA process,

- NERSA is empowered to make key decisions for the determination of infrastructure investment in the electricity industry. NERSA concurs that at least 65% to 70% of Eskom's efficient costs are fixed costs. The basis of these fixed costs are based on approvals made by NERSA. With regards to Transmission and Distribution infrastructure, Eskom implements in accordance with the NERSA Grid Code and Distribution Code requirements. Generation requirements are determined by the Integrated Resource Plan (IRP). It is assumed that NERSA, as any stakeholder, provided input into the finalisation of the IRP. When the Minister of DMRE makes a determination in terms of the IRP, NERSA is required to evaluate the requirement of particular generating capacity before concurring on the Minister's determination. After concurrence from NERSA, the DMRE Minister determines the procurement process to be followed. Once the procurement process has been finalised, NERSA is required to license entities that will provide the generating capacities. Included in the licensing process is the financial viability. Thus, it is submitted that NERSA has ensured that when a revenue application is made, the majority of the basis of the costs (fixed costs) have withstood the rigour of various NERSA analysis processes. When a revenue application is made, it is based on the previous approvals already made by NERSA.

- NERSA, in its revenue determination, also determines the sales volume to be assumed. NERSA undertakes an independent analysis to make this determination. In making this determination, NERSA evaluates the price elasticity impacts.

- As sales volumes increase or decrease, there would be a concomitant increase or decrease in variable costs, but not necessarily fixed costs. The key variable costs for the electricity industry are related to primary energy costs. Primary energy cost variances due to lower sales have been included in each of the primary energy cost elements in the RCA balance computation. Fixed costs include interest and debt repayments which are included in the returns and depreciation building blocks of the allowed revenue for regulatory purposes.

- The RCA mechanism that corrects for electricity demand under/over estimation is not mechanism to 'restore' sales volume and revenue to the estimated level, but rather is a mechanism to correct for such under/over-recovery of fixed cost caused by variances between estimated demand and actual demand, which it achieves by adjusting estimated sales volumes to align to what actually happened, and recalculates what price would have been on that basis, and thus revenue shortfall to be recovered through RCA. It has to be recognised, like NERSA, Eskom does not have control over such volume variances, whether higher or lower, as this is dependent on many factors outside of Eskom's control such as economic climate, commodity prices, civil unrest and, COVID.

- NERSA makes a decision based on sales volume that NERSA determined to be reasonable, according to its analysis. If the revised (lower) volumes had been deemed to be reflective of what could be achieved for each of the financial years, there would have been two different outcomes. The first is that the resultant price (in c/kwh) would have been higher – because the allowed revenue would have been recovered over a smaller volume of sales. The reason for the higher price is due to the recovery of the fixed cost elements. The variable cost elements are netted off as part of the operating costs. Thus, consumers are being allowed a subsidy in the first instance, since it was assumed that the fixed costs would be recovered over a larger sales volume. The variance is then recovered many years later, when NERSA allows for the recovery of the RCA balance. The opposite would also be true if volumes increased, resulting in lower price adjustments.

- It has been demonstrated that a 1% increase or decrease in volume (which presently equated to approximately 2 TWh) does not result in a significant change in price of electricity. It is thus surmised that when NERSA has to implement its mandate in accordance with the Electricity Regulation Act, with regards to allowing a licensee to recover efficient costs and a fair return, the focus should be on analysis of efficient costs and a fair return.

- Therefore, if NERSA wants to place all volume risk on the utility (including municipal distributors), the only way the utility can mitigate this risk is to ensure that tariff charges that recover fixed costs are not volumetric or to enter into take-or-pay contracts. Increasing fixed charges would impact low load factor customers the most. The likely outcome would be a substantial increase in prices for some customers. Eskom has been trying to migrate towards most cost reflectivity at a tariff level. An option to consider is for customers (especially larger customers) to take accountability for the forecasts they provide and if volume risk is fully placed on the utility, then this risk would have to be passed onto the customers that provide such information through mechanisms like take-or-pay contracts.

24 The ERA requires the recovery of efficient costs and a fair return – not guaranteed revenue

This consultation paper refers to a "*guaranteed revenue*".

It is best to consider what the legislation requires of NERSA. Simply put, it requires that NERSA must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return.

Revenue has never been guaranteed for Eskom or any licensee. The recovery of revenue is dependent on many factors. The sequence of processes when a revenue determination is illustrated by an extract of the affidavit deposed for case number 21896/2020 (The Judicial review of NERSA's decision on the FY 2018 RCA), by Mr Nhlanhla Gumede, the NERSA Full-Time Regulator Member primarily responsible for electricity as:

6. "NERSA is responsible for regulating electricity prices and tariffs. NERSA is empowered by legislation to develop a methodology or guide for it to do so.

7. NERSA has developed a methodology to guide its application of the broad principles in its electricity pricing determinations, known as the Multi-Year Price Determination ("MYPD") Methodology ("the methodology").

11. NERSA developed the methodology to ensure Eskom's sustainability as a business, promote reasonable tariff stability and consistency, allocate commercial risk between Eskom and its customers, and provide efficiency incentives.

12. The decision or determination in the context of the MYPD process:

12.4. takes place in two steps:

12.4.1. firstly, NERSA makes a provision of Eskom's allowable revenue (AR) by forecasting its efficiently incurred costs and reasonable return. This is owing to the fact that the price of electricity is determined in advance (before Eskom incurs expenses for that financial year and before the public makes use of the electricity). This forecast is not a restriction on what Eskom can spend in that financial year. It is a restriction on what Eskom can recover from the public during the financial year; and

12.4.2. secondly, the final determination of Eskom's AR takes place when the actual expenditure is available and NERSA is able to test it for prudency and efficiency through the Risk Management Control & Pass -Through Mechanism process, commonly referred to as the RCA process.

12.4.2 Once the expenditure is approved, Eskom is entitled to recover the balance in the next financial year after the RCA application, if there was any under recovery or the amount is clawed back, if there is over recovery. (Footnote in Affidavit - Irrespective of the tariff determination (forecast), Eskom will only receive the income from the public as they make consume of the electricity and pay for it. The public could consume substantially less or substantially more)

14. The analysis of the application involves:

14.4. An entirely fresh assessment of prudency and efficiency that takes place at the RCA stage. This is done on audited financials with information NERSA prescribes in the methodology.

14.5. NERSA making a decision on Eskom's allowable revenue only once the final actual costs have been assessed for prudency and efficiency. It is this decision that ought to permit Eskom to recover its efficiently and prudently incurred costs and the reasonable return."

Thus, based on the NERSA explanation above, it is further clarified that a final allowable revenue determination is made after the RCA determination. A prudency assessment is undertaken by NERSA prior to this determination. It is further clarified that to make the first decision at the revenue determination stage, it would be based on assumptions at that stage. The actual that manifests after the RCA determination represents the final allowable revenue.

It also needs to be noted that when NERSA makes its original revenue decision, it is based on an assumed sales volume. Thus, the fixed costs are recovered from the level of sales assumed at that stage. If the actual sales volume turns out to be higher or lower, then adjustments are made through the RCA. The variable costs will be aligned to the higher or lower sales volume. An alternate way of interpreting this that either Eskom provides an initial subsidy (if the original sales are higher) or the consumer provides a subsidy (if the original sales are lower). Thus, it is a matter of timing – not additional revenue. Thus, no guaranteed revenue.

25 Information provided by System Operator

The system operator dispatches in accordance with NERSA's Scheduling and Dispatch rules. This is in accordance with the merit order. It needs to be clarified that the merit order is defined by the variable costs and not the net cost of electricity. It is thus very likely that a generator with the lowest marginal cost (variable) has the highest net cost. It needs to be noted that the basis of determining costs is presently based on the allowable revenue decisions made by NERSA. Due to still migrating towards cost reflectivity, the actual costs are not covered by the revenue determinations. These shortfalls are funded by the fiscus.

The expectation that the System Operator will capture which generator supplied what amount of power and record the duration of supply is unrealistic. The System Operator will call up power plants in merit order to meet the different loads as they come onto the system and record which generators delivered power and how much over the 24-hour period.

These seems to be a dependence on the system operator to provide information on dispatched generators to enable the determination of recovery of costs by licensees. It is unclear how the process will be managed to ensure the recovery of efficient costs by licensees.

Eskom already undertakes merit order dispatch in terms of the NERSA Scheduling and Dispatch rules. It is thus unclear why this merit order dispatch is being introduced as if it does not occur.

26 Unclear on how Independent Power Producer revenue requirement is addressed

It is unclear as to how the revenue related to the costs associated with contracts between licensees and Independent Power Producers (IPPs) will be recovered. These are usually long-term contractual commitments that have been committed to and are likely to continue in terms of the ERA.

With regards to instances where Eskom has been designated the buyer, in accordance with section 34 of the ERA, particular legislative requirements are necessary. These are defined in the Government Support Framework Agreement (GSFA). In accordance with the section 3.1.4(e) of the GSFA, Eskom is required to consult with and seeks approval collectively from the Department of Mineral Resources and Energy (DMRE) together with the Department of Public Enterprises (DPE) and National Treasury with regards to the proposed amounts for IPP purchase costs and payment obligations to be included in revenue applications to NERSA for the Multi-Year Price Determination (MYPD) period. Only what is approved by these three Government Departments, can be included in Eskom's revenue application. It is understood that Government requires assurance that recovery of IPP related costs through the MYPD process. Since this consultation paper removes the requirement for an Eskom revenue application to be made, this assurance cannot be provided through the GSFA legislative requirement. This is seen as a risk to Eskom meeting its contractual requirements, the IPPs securing the recovery of their costs and possibly imposing liabilities on Government.

Any renewable technology generation is self-dispatch. Thus, it is defined as must-run and cannot be dispatched. The dispatch of renewables is not considered in the merit order – since they are must-run plants due to their nature. Additionally, the marginal cost of any renewable technology is zero. The principle that rather needs to be considered is that merit order is based on marginal cost – where the marginal cost of renewable is zero.

Indications are that accommodation is being made for IPPs not to be obliged to sell to Eskom or Municipalities. They conceivably will bid to provide their energy into the grid. It is unclear as to which legislation will allow for this to occur. It is understood that either Eskom or Municipalities have been designated buyers of energy from IPPs that wish to recover their costs through the regulatory processes. It is unclear how this methodology can accommodate such an arrangement, when it is not catered for in the ERA.

27 Tariff development and its relationship with cost

- The approval of costs and the design of tariffs are two separate and sequential processes. The two are interchangeably used in the NERSA consultation document. Tariffs do not determine the costs; they recover the allowable costs and cannot provide more revenue than that approved by NERSA (in a regulated environment).

- Tariff design is based on, and starts with a revenue determination, thereafter a cost-to-serve (cost-of-supply) allocation of allowed functionalised costs and finally a restructure or introduce new tariffs to reflect updated cost and cost drivers. In the absence of an update or restructure of tariffs, tariff category increases are used for year-on-year adjustments. Municipalities have to develop an interim revenue requirement in order to conduct a cost to supply study.

- Tariffs are therefore not designed based on the average price announced by NERSA, they are an outcome of the regulated cost plus return decision. This decision on regulated cost is a justification of prudent costs and allowable return. Only once the cost plus return decision is known, the revenue and approved volumes are used in a cost-to-serve exercise to allocate these allowed costs and from this tariff are designed. The cost-to-serve is not a cost justification process, it is a cost allocation process for the purposes of determining end-use retail tariffs.

- The Eskom submission to NERSA for the approval of tariff structural changes or new tariffs, is a separate process from the annual tariff adjustment process. This follows that the approval of changes in tariff structures or new tariffs is required before they are adjusted to reflect a new financial year's price level. Further, the NERSA regulation, ERTSA directs the determination of year-on-year tariff category increases requiring that annual increase submissions are exclusive of changes to tariff structures and limits the approval to a change in tariff rate levels through average price increases.

- The steps to determine and design tariffs are well documented internationally as a sequential process.

- The first determines the required level of annual revenue, typically known as the revenue requirement. This determination is crucial in understanding what the holistic, efficient costs including a fair return would be required by the utilities. This is also aligned to NERSA requirements in meeting its mandated role of allowing an efficient licensee to recover its efficient costs and a fair return. There are ample opportunities for NERSA to analyse, benchmark and thereby determine what this should be. It also follows that it is a matter of how NERSA undertakes its role within a defined, internationally recognised set of rules.

- The second phase which is the cost to serve - apportions the revenue requirement using functionalised divisional costs among justifiable and segmented customer categories, using cost drivers such as customer-related costs, demand-related costs and energy-related costs cost to serve

- The third phase where the tariffs or rates, are designed (structures and level) in order to collect the allocated cost from each customer category. This process takes into account, guided by national policy, the Codes and NERSA rules, sophistication of customer needs, metering, affordability, impact of changing from the existing tariffs, revenue risk (departing from the cost driver) and fairness.

– **Tariffs cannot determine costs**

- Tariffs methodologies described in the NERSA consultation document, presupposes that tariffs and tariff structures are used to determine costs. For example, there is discussion on how generation costs should be disaggregated into how they serve different customer categories. Generation costs are costs based on their assets and operating costs and not based on a customer's profile. How these are then charged to customer is a tariff exercise, and this cannot be based as proposed by NERSA on the load types.

- Tariffs cannot be designed based on individual customer usage, unless such tariffs are unique to a customer under a market-based approach. Even then, this would significantly increase the number of tariffs and would require NERSA to approve such individualised tariffs for each and every customer as required by Law. This in turn would mean that all other tariffs would have to be adjusted to come back to the revenue requirement. A change to one tariff or tariff category, means an equal and opposite change to another tariff category.

- It is for this reason costs are generally pooled into homogenous and identifiable cost categories when doing a cost-to-serve exercise (after the cost have been approved). Any results from this exercise leading to tariff changes always mean someone will pay more and someone will pay less.

- There is considerable confusion on how NERSA setting load type tariffs based on the four load profile types will be translated into tariffs applied at the customer level and what would be the wholesale tariff that licensees purchase at. Some questions that are not answered in the consultation paper, for example:

  – Are the various "*WAT*" the energy tariff to be applied?

  – Time of use is mentioned in the document as a tariff option – how does this fit into type of use and the WAT formula?

  – What purchase tariff would apply to the licensee who has millions of customers all with different load profiles?

– If NERSA sets the tariffs for customers based on competitiveness, what role would licensees have in tariff approvals – only network charges?

28 The NERSA Cost to supply framework – which is being reviewed.

On 29 October 2015, the NERSA approved a Cost of Supply (COS) framework to be used as a guideline by all Licensed Electricity Distributors for conducting COS studies and licensees that had the ability could expand on the framework to a level that met their specific needs.

The aim of the NERSA COS framework was to satisfy the requirements of the Policy Position 23 of the Electricity Pricing Policy (EPP) of 19 December 2008 that requires Distributors to conduct a Cost of supply study at least every 5 years using a NERSA approved standard to reflect changing costs and customer behaviour.

The COS framework provides the NERSA standard for Licensed Electricity Distributors allocate costs with the goal of rate setting informed by an embedded cost approach that:

- Recognises a revenue requirement as the level of costs to be used in the cost allocation. The revenue level is to satisfy the EPP Policy Position 1 that for a level that covers the full cost of production including a reasonable risk adjusted margin or return on appropriate asset values. In the absence of a revenue requirement as is the case for municipalities, an interim revenue requirement that is the sum of all costs anticipated in the application is to be used as a basis for the cost of supply study.
- Requires Licensees to arrange costs along major operating functions of a licensee to facilitate a determination of customer groups contribution to the costs. This process referred to as cost functionalisation separates and arranges costs along production/generation, transmission, distribution or customer-related functions.
- After the cost functionalisation Licensees need to ensure that the arranged costs are further disaggregate into sub-groups in a manner that clarifies the relationship as a measurable cost-defining characteristic of rendering the service; the cost classification. Consequently, this break-down or classification differentiates fixed from variable costs, demand-driven, usage or energy and customer / retailing-related costs.
- The cost allocation is the final process of the framework providing unit costs for use in rate determination or in the development or update of tariffs. The classified costs inform the cost allocation to customer groups separately for energy, transmission, distribution networks and retail using cost drivers. The NERSA cost allocation methodology is shaped to allow for a transparent view of the electricity value-chain by ensuring:

- Energy consumed is a cost driver to allocate energy costs as it varies energy costs by time of use and incorporates the cost of network losses associated with consumption.
- Customer demand is a cost driver to allocate network costs as network costs are influenced by the demand level. The costs classified under network costs are network capital costs, the operations and maintenance cost of networks, demand purchase cost (if applicable) and the wires component of the purchase cost (if applicable). The use of the average and excess methodology to allocate network costs is advised since it allows for the allocation of network costs following that if a customer group uses a specific network asset, the customer group is included in the allocation of the cost of the asset group.

29 Cost to serve

This process starts with the approved cost-plus return (revenue) and then costs are allocated as follows:

- Classified costs are allocated to customer categories
- based on applicable cost drivers
- using an appropriate cost allocation method
- to produce unit costs per customer category/cost type

Cost justification is done by Eskom through the NERSA rules and approval process, where Eskom motivates revenue to cover return, depreciation, and operating cost, and NERSA decides on the amount to be approved through the allowable cost recovery process. The approved revenue requirement and volumes are the values used in the cost-to-serve study exercise.

The tariff design uses cost units from the cost-to-serve study. The cost-to-serve study is an embedded cost-of-supply study allocating the Eskom allowable revenues from an MYPD decision related to Eskom's standard tariffs by customer categories that are segmented by supply voltage and location density.

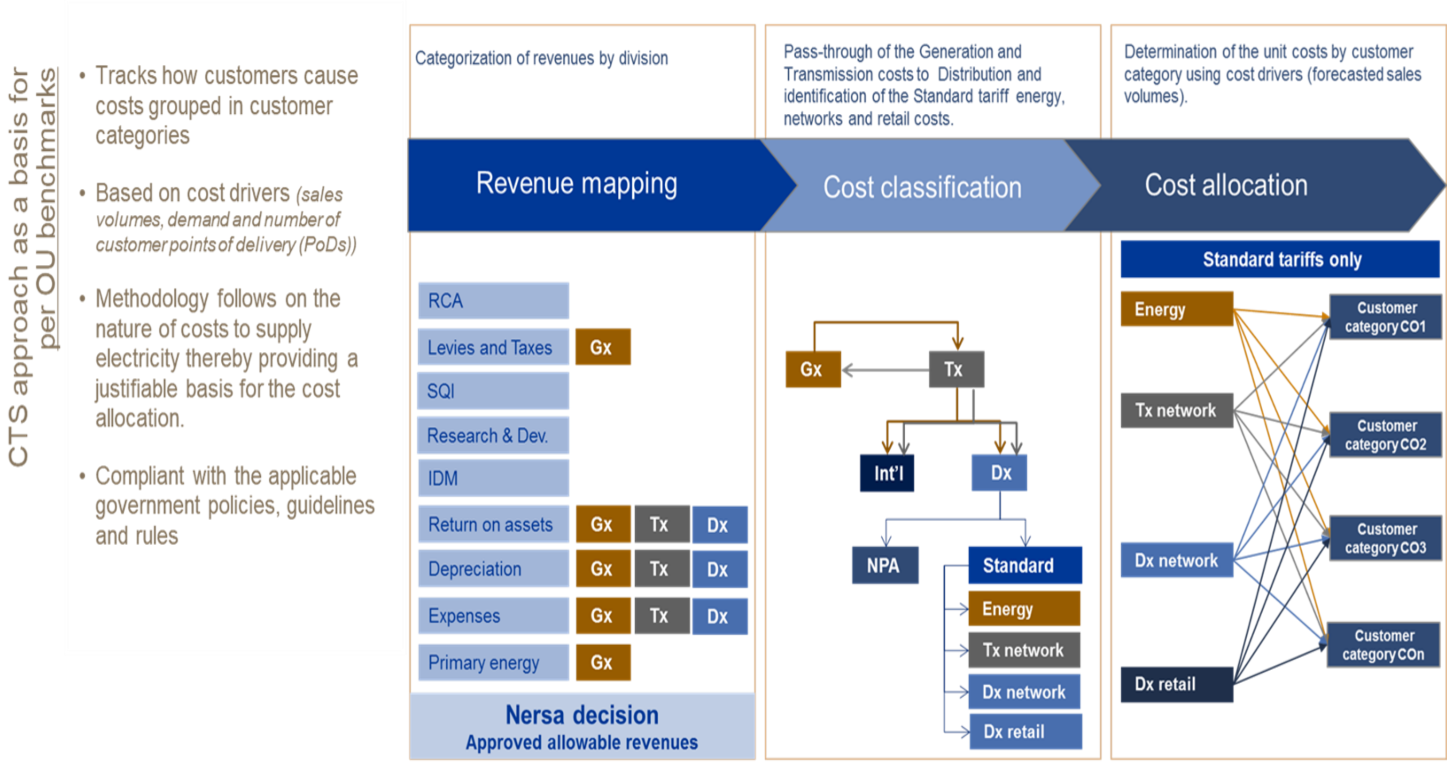
The cost-to-serve study cost allocation is guided by a cost causation principle; that is, it tracks how each customer category contributes to the costs to supply electricity based on its consumption and demand. The cost drivers used in the cost allocation are the volumes used in the NERSA MYPD decision for the costing year, that is, the sales in kilowatt-hours, the demand (utilised capacity, maximum demand, and chargeable demand), and the number of customer points of delivery (PODs).

The cost-reflective unit costs from the cost-to-serve study are then converted to measurable units to reflect cost drivers.

The following are the most common cost drivers in the electricity business:

- R/customer/month or R/customer/day charge - typically for customer service and administration costs.
- R/kVA - typically for network or capacity-based costs.
- c/kWh - typically for energy costs, return and taxes.
- c/kvarh - reactive energy costs.
- R/Amp - to recover energy or network costs.
- Energy loss factors for energy loss costs.

Figure 1: Illustration of Cost to Serve study



30 The tariff design process

The type of price components put together in a tariff package is the tariff structure. The ideal tariff structure would therefore follow the cost structure. A cost-reflective tariff structure has all cost components reflected separately and charged according to the appropriate cost driver per appropriate rate unit. Eskom supports the unbundling of costs in the design process as far as practically possible to determine the charges used to recover those costs and ultimately form the tariff structure.

Tariffs are designed to provide current and future price signals that are forward looking, but still designed to recover current approved revenues. Rates must satisfy numerous objectives, some of which may be in competition with others. Generally, and universally accepted and still relevant today are the following pricing principles set out in Professor James Bonbright book Principles of Public Utility Rates, summarised as follows:

a) Sufficiency: Rates should be designed to yield revenues sufficient to recover utility costs.

b) Efficiency: Rates should provide efficient price signals and discourage wasteful usage.

c) Fairness: Rates should be designed so that costs are fairly apportioned among different customers, and "*undue discrimination*" in rate relationships is avoided.

d) Customer acceptability: Rates should be relatively stable, predictable, simple, and easily understandable.

The type of price components put together in a tariff package is the tariff structure. It is supported by the ideal tariff structure would be unbundled to follow the cost structure. However, tariff design is not just about reflecting costs, it is also about reflecting price signals that drive consumption behaviour to optimise system and cost efficiency

A cost reflective unbundled tariff structure has all cost components (energy, networks and retail costs) reflected separately, and charges are raised using the most appropriate tariff charge type needs to be established. The tariff structure to be used may be dependent on:

- Revenue and volume risk (departing from the cost driver)
- What pricing signals need to provide
- Sophistication of customer needs
- Metering – can it be measured?
- Affordability – do subsidies need to be accommodated
- Impact of changing from the existing tariffs.
- Cannot be discriminatory

31 Tariff structure challenges include:

The most cost-reflective tariff will reflect in its structure and level, the cost drivers/categories as accurately as possible, but this tariff structure is complex.

- A tariff may be cost-reflective on average, per customer class or even per customer and the more averaging the less cost-reflective to a particular customer, but the simpler the tariff becomes.
- It is not possible to have total cost reflectivity per customer as this would significantly increase the number of tariffs and therefore similar or homogeneous costs are always pooled
- Meter capability, billing functionality, logistics and customer response force aggregation when reflecting the various cost components and cost drivers in a tariff.

32 A cost reflective tariff structure to recover electricity costs will typically contain:

- Energy charges – including a signal to reflect time and seasonal variance to reflect system constraints (not type of use) and in future a generation capacity related charge to reflect the cost of providing standby capacity
- Transmission network and ancillary service charges
- The Distribution network charges
- Retail (service and administration) charges
- Differentiation to take into account:
  - Geographic location
  - The voltage of the supply.
  - The electrical (technical) losses.
  - Reactive energy support.
    - The density of the network to which customers are connected.
    - The load factor/profile.
    - The size of the supply and the services being provided to the customer.

Eskom currently has largely unbundled tariff structures for most customer categories and the extent of unbundling depends on the customer category. Eskom in its retail tariff plan submission provided NERSA with extensive detail on further unbundling based on a new cost-to-serve study and how the proposed tariffs and tariff structures would be derived. The

Distribution Tariff Code in provides a useful explanation on tariff design principles, which are aligned to the EPP. It is noted that in the Consultation paper that no consideration was given to this process.

A point to be noted as well, is that Eskom already has NERSA approved wheeling tariffs and based on a non-discriminatory approach, these tariffs are applicable to all users of the grid, whether supplied by Eskom or by a third party. These tariffs are our unbundled network use-of-system charges.

How tariff design and end-use tariffs to customers will work is however, as noted previously is no clear.

33 Impact on consumers to be considered before tariff adjustments are made

As part of any changes in tariffs, it is essential to first determine the impact of any changes before making the final decision. The revenue (efficient cost and reasonable return) will be recovered through various tariffs. When changes are made to tariffs there is a likelihood that customer groupings will be impacted. It is likely that certain customers would be positively impacted and certain customers would be negatively impacted. This also points to the merits of phasing-in of any changes. Any sudden change will likely to have severe impacts that could result in changes that will require particular attention. A big bang approach will likely to have catastrophic impact.

In addition, cross subsidies are an essential element of managing the impact on vulnerable sectors, such as poor residential customers. The cross subsidisation, as a policy decision, has been included in the EPP. The first element in this section, that seem to be lacking in this consultation paper, is the need to undertake impact assessments before making any decisions. From what could be inferred in this consultation paper is that residential customers are likely to see an overnight increase of between 30% to 50%. The second element, is that indications are that the consultation paper indicates that cross subsidies may not be necessary. Cross subsidies are a policy position included in the EPP. The removal of cross subsidies is likely to further contribute to impact on the residential sector.

There is always a balancing of conflicting priorities to be considered. Choices have to be made between the winners and losers meaning that whenever tariffs are changed someone will pay more and someone will pay less. Most concerning is that the Consultation Paper on the concept of "*load type*" implies that industrial customers receive the allocation of the lowest cost electricity generation and that all other customers will pay for variability. This would have a significant negative impact on traction, agriculture, residential, commercial and most importantly Eskom's municipal tariffs. It is not clear in the Consultation Paper how the concept of marginal pricing will flow through into tariffs and ensure adequate recovery of costs.

In conclusion to this section, we wish to highlight the following passage taken from NERSA's Guidelines for the Determination of Municipal Tariffs which we commend;

"In the absence of competition, regulators may select from a range of methodologies to regulate the industry. All these options have various advantages and disadvantages. Regardless of the method of regulation or price formation, it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that will allow it to operate as a viable concern, now and in the future. Moreover, it is important that the regulated business is able to attract reasonably priced finance in order to maintain, refurbish and grow its infrastructure and provide services at a reasonable cost. As a result, tariffs must be set at a level that will not only ensure that the utility generates sufficient revenues to cover the full costs (including a reasonable margin or return), but will also allow the utility to obtain reasonably priced funding"

34 Specific comments

i. The proposal per par.5 that a tariff approved by the regulator may be amended or withdrawn unilaterally by the regulator, with the only proviso that there must be " … *due consideration of any written presentations made by the Licensee concerned*" would (if allowed to stand) significantly increase revenue uncertainty and regulatory risk, to the degree that it will severely constrain the ability of licensees to attract capital thus breaching the objectives of the Electricity Regulation Act such as "… *to facilitate investment in the ESI".*

ii. The 'cost allocation' proposals of par. 8(6) and 8(7) are not only unimplementable and would (were it implementable) send distortive economic signals, it is completely superfluous, given that after having allocated costs to products / services, it is not necessary to 'allocate costs to consumers'. This is automatically and accurately taken care of by virtue of consumers using more / less of each service. Thus, the quantum of each service as used by each consumer determines the 'allocation of costs to each consumer'. Were it implementable, NERSA's proposals will be extremely distortive thus contradictory to the requirements of the EPP.

iii. Regarding the proposal per par. 9(4)(d) that an activity's costs "*in respect of capital investment, must be used and useful*", it needs to differentiate between assets ceasing to be used and useful due to management actions or failures, as compared to being due to events outside management control, such as changes in legislation, etc. Failing to make such differentiation will imply a breach of NERSA's principles for assessment of prudency, by implying the application of hindsight to retrospectively assess an investment into an asset, which was originally assessed as 'prudent and efficient', as 'not prudent and efficient' any longer. This would also be in breach of the requirement of the Electricity Regulation Act to allow the full efficient costs related to a licensed activity to be recovered.

iv. It would furthermore significantly increase the already-high inherent investment risk of infrastructure assets, thus would further disincentive investment of capital into the industry – a crucial matter given that the lack of capital investment is at the core of the country's lack of generating capacity. NERSA's approach will thus imply an additional hurdle to efforts to solve the electricity supply crisis in SA

v. Par. 10 does not mention the inclusion of Works Under Construction into the RAB, which will cause price spikes upon the commissioning of new assets, and further increase the hurdle to capital investment into the ESI, thus breaching the objectives of the Electricity Regulation Act such as "… *to facilitate investment in the ESI".*

vi. The WACC formula per par. 10(2)(c) is incorrect in twice including Ke, instead of Ke and Kd.

vii. Par. 10(4)(b) states that the licensee will be required to "*report the cost variances with respect to primary energy*" – it is unclear what the reference value is for calculating these variances.

viii. The formulas for accumulated depreciation (i.e. Ac*y*0 and Ac*y*1) as given under par.10(5)(b) is incorrect. As written, it is a formula for 'depreciated MEAV'. If used as provided it will result in negative annual depreciation (note that this error also appears in the MYPD methodology).

ix. Par.10(6)(b) states that levies are "…*determined by Government, are actual payments and will be treated as allowable costs*". This implies that revenue will have to adjusted retrospectively to deal with any variances between the original estimates (upon which revenues and tariffs for the future period were based) and the actual outcome, however it is unclear how such retrospective adjustment mechanism will work. This similarly applies to par.14(9), etc.

x. Par.10(6)(d) similarly state that *"…. municipal surcharges fit the definition of the government levies and taxes, these need to be excluded from the municipal Tariffs and expressly captured and reflected as pass-through costs*", however it is unclear how such pass-through mechanism will work and how any retrospective adjustment mechanism will work.

xi. The entire par.11 relating to 'Consumer Demand Analysis', as was explained above, is unimplementable from both a conceptual/principle perspective as well as from a practical perspective. It furthermore reflects a misperception about economic fundamentals which (were it implementable, which it is not) would send distorted economic signals that would create dysfunctional and perverse incentives and unintended consequences, which would be in contravention of government's Electricity Pricing Policy. This similarly applies to the entire par.12 (Merit Order Dispatch), to the degree that it deviates and goes beyond the existing requirements of the Grid Code etc. regarding merit order dispatch, as well as to the entire par.13 (Consumer price build-up), as well as par.14 (Data collection), especially par.14(5).

xii. The exception to the above is par.13(11)(a) "*Energy charges and capacity charges will be reflected separately on customer bills*", which is supported. However, it is unclear how par.13(11)(b) that states "*Fixed charges will be allocated based on the relative Consumption of each consumer of that load*" would work – it seems to defeat the entire purpose of 'fixed charges' – unless it means 'relative notified maximum demand' or similar.

xiii. It is unclear how par.17(8) which provides that *"… the Regulator may approve automatic monthly or quarterly increases to reflect increases that are not under a Licensee's control or influence*" would work in practice.

35 Recommendations and Way Forward

35.1 Need for impact assessment

It is highly recommended that as NERSA finalises this methodology an impact assessment be undertaken. The key reason being that the proposal is making radical changes where the impact cannot be easily ascertained. It is proposed that the following be included:

- Assessment on ability to implement the methodology
- Assessment on ability to invest in and /operationalise necessary infrastructure, systems, processes
- Impact on various customer groupings
- Impact on sustainability of all licensees to continue to operate
- Assessment on all licensees to deliver on the requirements of the methodology
- Assessment of ability of fiscus to support proposals
- Assessment of ability to provide incentives for investment in electricity infrastructure
- Assessment of ability to provide incentives for investment in the country
- Assessment on the reputation of the country as making progress in electricity price regulation

- Assessment of NERSA's ability to meet its mandate in terms of the legal regime
- Cost benefit analysis of implementation of the methodology
- Assessment of alternatives that could meet the majority of the objectives
- Assessment of policy, legislative and regulatory changes that are needed prior to implementation of the methodology
- Clarity on impact if proposals could possibly be implemented.

35.2 End-Customer Impacts

The impact on end-customers and licensees is totally missing and therefore licensees and customers would not be able to assess what the impact of this methodology would have on them. It is also not possible for Eskom to do such analysis due to the convoluted approach being proposed by NERSA and there are just too many questions that would still need to be answered Actual examples comparing the current methodology and tariffs against that proposed would be required to make meaningful inputs.

There is also no consideration how licensees would be able to carry this approach, in particular the load type concept through to their customers.

35.3 Cost to serve methodologies are applicable

The Cost-of-Service (CoS) approach to ratemaking is the international standard for utility regulation, and for good reason. By establishing an electric utility's tariff at a level that reflects the true long-term costs of providing the service, the CoS approach promotes the efficient use of electricity by consumers, ensures the utility remains financially sustainable and able to raise private capital to invest in new capacity when required and ensures that electricity consumers bear the full cost of the service they receive. Thus, for both economic efficiency and equity reasons, CoS tariffs have been the cornerstone of good utility ratemaking for over a century.

<u>This CoS is used in the USA for over 100 years and in many other jurisdictions</u>
"The cost of service is defined as the sum total of (a) proper operating expenses; (b) depreciation expense; (c) taxes, and (d) a reasonable return on the net valuation of the property."

<u>Ratemaking is not simple, even if the basic formula can be simply stated:</u>
Annual Revenue Requirement / Cost of Service Formula
Operating & Maintenance Expense (including primary energy)
\+ Depreciation Expense
\+ Tax Expense

+ Return on Rate Base

= Annual Revenue Requirement/Cost of Service

The process of estimating the revenue requirement for ratemaking starts with the establishment of the rate base, followed by an estimation of the weighted average cost of capital. These two elements are used to establish the "*Return on Rate Base*" of the Cost-of-Service Formula. Each of the four elements requires the input of numerous studies, estimates and calculations with opportunities for differences of opinion among stakeholders. The projected sales volumes being assumed are critical to allow for appropriate revenue requirement.

The Rate Case Process indicates the following steps in establishing rates under a Cost-of-Service methodology.

a) The establishment of the annual revenue requirement based on the approved cost of service elements is the first decision necessary to be made by the Regulator. This is equivalent to NERSA's MYPD methodology. The revenue requirement in the MYPD methodology can also be further separated into Generation, Transmission and Distribution.

b) A Cost of Service "*study*" allocates the costs to each of the customer classes or services identified by the Regulator. The principle applied here is that the study should assign cost responsibility on the basis that "*the cost-causer is the cost-payer*." This is equivalent to NERSA's requirement for a cost-to-serve study.

c) The last step is tariff design – the process of designing individual rates for each customer class, considering how fixed costs and variable costs will be apportioned to be collected in fixed or variable charges. This is equivalent to the ERTSA methodology.

Variations to the CoS methodologies include fair value, original cost, performance-based or incentive regulation, yardstick and benchmarks, to name a few.

- The Yardstick or benchmark regulations are indirect methods of estimating the Cost of Service of a specific utility. This method entails finding a similar utility or utilities whose costs can be used as a proxy for the subject utility. The assumption here is that the costs of the proxy utility are lower or acceptable primarily because of reasonably competent management and not external factors such as geography, local economic conditions or different regulatory requirements. The method is used mainly where cost data for the subject company is just not available or suspect. The method also requires access to comparable utilities, which is a rare situation.

It is worth re-emphasising the point that any variant of traditional CoS regulation, performance-based or incentive regulation, and earnings sharing starts with the setting of cost-based tariffs.

- The Cost of Service study (i.e. refers to NERSA's cost-to-serve study), also referred to as a "*fully allocated cost of service study*", is an analytical tool that assigns or allocates each relevant component of cost on a reasonable basis to determine the relative cost to serve each customer class.

- The objective is to apportion the total utility costs among customer classes in a fair and equitable manner. This is frequently referred to as "*cost causation*", and the "*Cost causer is the cost payer*" principle.

- The exercise attempts to assign the costs of the system to the customer (or customer class), which causes the cost to be incurred. A full cost of service study (CoSS) takes the annual cost of service or revenue requirement estimate. It allocates those total costs to the appropriate customer class and then designs rates within each class, to meet regulatory requirements. These types of studies require input from all departments of the utility.

- The essential Cost of Service Study design concepts were developed in the 1890s. The earliest electric rate engineers understood that electric service included the provision of power capacity (watts) and energy (watt-hours) and that service was required instantaneously with the plant in service standing by 24 hours, seven days a week, to be available at the customer's demand. Hence electric utilities required large, fixed capital investments to be on standby to meet peak power requirements, but these would sit idle the rest of the time.

There are three basic steps to an allocated cost of service study:

a) **Functionalisation**: the first step is to allocate the revenue requirement to each of the four primary operating functions of a utility - generation, transmission, distribution, and general costs.

b) **Classification**: Once the revenue requirement (total cost) has been separated by function, the second step is to allocate these functionalised costs to cost drivers. These are typically split into four main categories - demand, energy usage and customer-related and direct. Demand costs are related to the total available capacity the system must provide to instantaneously meet peak demand across the entire system and for each customer. Demand costs are typically fixed - they remain constant regardless of the volume of energy consumed. They are predominately associated with the capital investment required to ensure there is sufficient capacity to meet peak customer and system demand.

The "*energy*" costs increase with the amount of electricity that is consumed in a given period and are typically variable (, e.g., fuel and other materials). The "*customer*' costs vary by the number and type of customers served and are associated with the costs of maintaining customer accounts, billing records, bill creation etc. The "*direct"* costs are those unique to a particular customer class and are easily identifiable from property records or specific activities attributable to that class or customer.

c) **Allocation**: the third step is allocating capacity demand, energy and customer costs to each type of service offered. Typically, the allocation is to residential, commercial and industrial services with sometimes the addition of specialised services such as street lighting or DC service for trolleys.

Once costs have been allocated to the respective customer classes, they are translated into tariffs that will enable the utility to recover its total costs (reflected in the approved revenue requirement) from its customers. The tariffs are designed to allow the utility to recover its full costs, but this is conditional on the assumption that total demand and energy (sales for the reference year) will be in line with the regulator's approved estimates/forecasts. If total demand or energy proves lower than the estimates the Regulator approved, the utility will under-recover its costs. And, if they are higher than expected, it would over-recover its costs.

When designing tariffs, the tariff analyst must consider not only the costs of serving each customer class but also a number of tariff principles and objectives. Rate design is as much an art as it is a science since electricity rates fulfil several functions besides collecting the full cost of service, while the development of the revenue requirement is more of a science.

The process discussed above is a globally accepted norm on how the rate-making process is regulated across electricity regulators. The existing regulations in NERSA's portfolio for rate making align to this process and is the best alternative to a transitioning industry.

a) NERSA's MYPD methodology includes cost-of-service and incentive ratemaking components, making it one of the most progressive and modern electric utility ratemaking schemes worldwide. This can be further revised to provide a revenue requirement at the level of Generation, Transmission and Distribution addressing NERSA's concerns of unbundling to a functional level.

b) The objective of the retail tariff plan is to reflect costs more accurately by:

- Avoid unjustified over/under-recovery of costs from customers and creating unintended subsidies.
- Ensure fairness and equity and transparency of subsidies existing in the system.
- Include use of systems costs for generators.

This ensures customers are provided with the correct information as per section 15 (1)(c), which requires that tariffs "*must give end users proper information regarding the costs that their consumption imposes on the licensee's business*."

c) Time-of-use (TOU) tariffs as a proxy for marginal costs provides incentives to customers to save if they shift load. This time-differentiated allocation of all costs (investment costs, maintenance costs, fuel costs) provides a more accurate tracking of costs of all types of generation to the consumption it serves. It promotes the efficient use of resources in a constrained supply environment by sending the correct pricing signals and is transparent and fair which and will not discriminate between users.

d) The load type tariffs do not promote efficient use of the system as it does not send the correct pricing signals to shift demand because it is a flat-rate. This tariff regime is discriminatory to some users and will result in disputes from many customer categories.

35.4 Eskom's RTP implements key objectives

Eskom last revised its tariff structures in 2012 and proposed unsuccessfully oto NERSA structural changes to the Eskom tariffs both in 2020 and 2022, based on two respective updated cost-of-supply (or cost-to-serve/CTS) studies.

There are various reasons Eskom is proposing changes to its tariffs; firstly the different tariff rates no longer reflect the different services being provided (that is, not aligned with energy, network and retail costs) due to the application of average price increases, secondly the unbundling of Eskom divisions requiring that the charges are more reflective of the costs per division, and thirdly the energy industry is evolving and tariff structures also need to evolve to protect all customer interests and to ensure adequate recovery of NERSA approved revenue by Eskom.

The consequences of applying average increases to rates is that there is currently no link between the charges raised and the NERSA approved cost per division, only that the overall sum of all charges recover the approved MYPD revenue decision. Tariffs therefore need to be updated to accurately reflect current Eskom divisional cost to avoid volume and trading risk, to reflect cost drivers more accurately, to avoid unintended and unwarranted cross-subsidies, and to ensure tariff charges cater for the unbundling of Eskom.

Currently Eskom Distribution sets the standard retail tariffs for all customers. The retail tariffs recover the approved MYPD revenue for the whole of Eskom to direct customers and municipal licensees. Eskom Distribution purchases the energy at the Wholesale level and Transmission services through an internal transfer mechanism and this is a pass-through in the standard retail tariffs.

Eskom in 2020 and in 2022, submitted proposed structural changes to NERSA based on the principles in the EPP and NERSA previous decisions. The 2022 s submission was an update of the 2020 submission, based on the same motivations used in the 2020 submission, the latest CTS and includes the further unbundling of the energy charges into fixed generation capacity charge and variable TOU charges to align with the wholesale purchases. NERSA's non-approval of both the retail tariff plans is a cause for concern due to the unbundling of Eskom, tariff charges not aligned with costs and creates an industry that is in limbo and cannot move forward with proper tariffs.

The following are the main objectives of the tariff restructuring submission:

i. To reflect unbundled costs more accurately

Different tariff rates no longer reflect the different services being provided (that is, not aligned with divisional energy, network and retail costs) due to the application of average price increases. The consequences of applying average increases to rates is that there is currently no link between the charges raised and the NERSA approved cost per division, only that the overall sum of all charges recover the approved MYPD revenue decision. Tariffs therefore need to be aligned with an updated cost to serve study to accurately reflect current Eskom divisional cost to avoid volume and trading risk, to reflect cost drivers more accurately, and to ensure tariff charges cater for the unbundling of Eskom.

ii. To reflect the changing electricity supply and demand environment

Existing tariff structures are outdated and need to be modernised to reflect the changing electricity environment and crucial decisions in this regard are needed to protect the electricity industry. For example, customers are installing own generation and using the grid in different ways and wheeling of energy is expanding. Fair and equitable revenue recovery from all customers for the services provided can only happen with tariffs and tariff structures that reflect this changing environment.

iii. Alignment between wholesale purchases and retail tariffs

Currently, Eskom Distribution purchases all its energy and Transmission network services from Eskom Transmission through an internal transfer mechanism. These purchase costs form the basis for the retail tariffs. Correct cost recovery reflecting the wholesale purchase costs is vital as there cannot be a disconnect between the wholesale tariff levels and structure and the retail tariff levels and structure, that is, purchases at one tariff structure and sell at another.

It is necessary that the wholesale purchase structure and rates is correctly reflected in retail tariffs and this submission includes the changes and motivation for this. In the future this may be done as a separate process to the retail tariffs, meaning future separate revenue decisions and separate price increases on new NERSA methodologies including ERTSA.

iv. Mitigate volume and revenue risk

When tariff charges recover fixed costs through volumetric charges, any reduction in sales results in a reduction of revenue, but not necessarily an equal reduction in costs. In order to ensure adequate recovery of costs, this means there needs to be an evolution in the thinking of how fixed costs can be recovered in tariffs.

It is important to realise the value of a grid connection and to pay a fair unsubsidised contribution for the use of the grid (network capacity) and the system (generation capacity). The grid and system provide backup, stability, and frequency control, can be used as a battery, provides standby capacity when needed, and provides the ability to receive compensation for energy exported.

In addition to recovering fixed network costs, generator costs should be recovered through a combination of fixed capacity charges (R/kVA) and energy charges (c/kWh). This will reduce the financial risk associated with recovering fixed costs through volumetric charges given the growth in variable energy resources, which also require back up capacity.

The following major structural changes[2] to the retail tariffs are proposed:

a) Designing all charges using the updated NERSA approved forecast volumes, Divisional cost splits, and cost allocation methods:

– **Energy c/kWh rates to reflect internal wholesale energy purchase structure; changes to the TOU ratios (peak, standard, and off-peak) and TOU periods (swopping the peak period and introducing a standard period on Sundays) to be aligned with the wholesale rates**

About 80% of Eskom sales are on TOU tariffs. These tariffs have peak (most expensive), standard (medium) and off-peak (cheapest) hours and charges, as well as having a winter/summer differential. Customers have requested both Eskom and NERSA to review the TOU tariffs, expressing concerns that the high winter TOU energy rates prohibit the optimisation of their production and impede their economic efficiency, which has a negative impact on their financial sustainability, their competitiveness in the global economy, and their ability to grow. Furthermore, both the Eskom shareholder and NERSA have asked Eskom to modify the TOU pricing.

The current TOU charges were last changed in 2005 and no longer reflect the present system and customer requirements. As a result, the current price signals and TOU hours are not optimal for managing the system and therefore changes to the wholesale purchase price structure are being proposed to assist the System Operator to optimise how the Eskom's system is managed, scheduled and dispatched.

– **Splitting the energy charges, based on the internal wholesale purchase energy price into variable TOU c/kWh charges and a fixed generation capacity charge –**

Given the fixed and variable costs of generators, the view is that generators' costs should be recovered through a combination of capacity charges (R/kVA) and energy charges (c/kWh). This will reduce the financial risk associated with volumetric recovery rates given the growth in variable energy resources, which also require back up capacity. The introduction of a fixed generation capacity charge (GCC) will result in a reduction of the variable c/kWh charge. The GCC is based on allocated costs for LPU tariffs and phased in 50/50 (fixed/variable) for SPU

[2] The type of price components put together in a tariff package is the tariff structure. The ideal tariff structure would therefore follow the cost structure. A cost-reflective tariff structure has all cost components reflected separately and charged according to the appropriate cost driver per appropriate rate unit.

tariffs to minimise the impact on these customers. The plan is to gradually increase the SPU tariffs' GCC to be 100% aligned with the wholesale purchase cost.

– **Network charges to reflect Transmission and Distribution network costs**

Transmission and Distribution network charges no longer reflect the network costs due to the application of average price increases. The consequences of applying average increases to rates is that there is currently no link between the charges raised and the NERSA approved cost per division, only that the overall sum of all charges recover the approved MYPD revenue decision. Tariffs therefore need to be updated to accurately reflect current Eskom divisional cost to avoid volume and trading risk, to reflect cost drivers more accurately, and to ensure tariff charges cater for the unbundling of Eskom.

– **Retail charges to reflect the Distribution retail costs.**

Similar to point c. above, retail charges no longer reflect the retail costs due to the application of average price increases and need to be updated with an updated CTS to accurately reflect the costs.

b) Increasing the Distribution fixed-charge network charges component, with a commensurate reduction of the variable charge for all tariffs with network charges

The Distribution business network costs are fixed in order to deliver the capacity needed. If network charges are not cost-reflective and recovered through variable/volumetric charges such as c/kWh, this places the Distribution business at risk of not recovering costs with reduced volumetric sales.

There needs to be a fair recovery of costs by all users of the grid so that tariffs more accurately reflect the value of the service being provided and that unintended subsidies are not created.

c) Rationalising the local-authority tariffs into only three tariff categories: a large power user (LPU) version called Municflex, a small power user (SPU) version called Municrate, and a Public Lighting tariff for non-metered lighting supplies

The proposal is to combine Eskom's existing suite of multiple tariffs applicable to local authorities into only three tariff categories. This will reduce complexity and simplify the sales and revenue forecasting process in both Eskom and municipalities.

d) Increasing the lower-voltage charges for urban LPU tariffs, thereby reducing the contribution to the low-voltage (LV) subsidies

The low voltage subsidy is an intra-tariff subsidy. Intra-tariff subsidies are when one charge is subsidised by another charge within a tariff category; for example, Megaflex higher-voltage network charges subsidise the lower-voltage network charges. The proposals in this retail plan have reduced some of the intra-tariff subsidies in order to rebalance some of the subsidies within a tariff category.

e) Basing service charges on the number of points of delivery (PODs) and not per account

Currently, the administration charge is per point of delivery, and the service charge is per account. Eskom proposes changing the methodology so that both the administration charges and the service charges will be raised per point of delivery and differentiated on size. The rationale is that a customer could have many PODs under one account and pay the same service charge as a customer who has one account and one POD. This is not equitable or fair, as more retail resources are used where there are multiple PODs to one account.

f) Removing IBT for Homepower and Homelight tariffs

IBT as a tariff structure is no longer appropriate due to customer perceptions and provides uneconomic incentives for customers that install embedded generation. Eskom proposes the removal of the IBT structure and replacing it with a single energy rate charge. For Homepower, the GCC and, more cost-reflective network and retail charges are introduced.

g) Introducing a residential TOU tariff plus a new net billing offset rate for customers with small-scale embedded generation (SSEG)

Eskom proposes the introduction of a residential time-of-use tariff, called Homeflex, for its urban residential customers. This tariff is more cost-reflective in structure, aligned with the changes made to Homepower, but with TOU energy charges. This tariff also includes TOU offset rates for compensation for energy exported onto the grid.

h) Amending the Transmission loss factors for generators so that the loss factors in specific zones are no longer negative.

Eskom is proposing to amend the current loss factors applicable to Transmission connected generators. Currently in certain Transmission Zones the loss factors are negative, effectively meaning that Eskom could pay a generator for locating in this specific zone. This principle at the time assumed a generator whose injections increase transmission losses faces a positive loss factor, which results in a charge, while a generator whose injections reduce transmission losses faces a negative loss factor, which results in a rebate. It is, however, not possible to pass-through negative charges, and for this reason Eskom is proposing that the loss factors for the Cape and Karoo zones are set to 1 (that is, will no longer go negative).

35.5 Overall revenue impact

When updating tariffs using a CTS study and implementing structural changes, it is not possible to have zero impact on all customers. So, while the total tariff revenue due to the structural changes is stays the same, that is, comes back to the MYPD approved revenue requirement, individual customers may pay more or less, depending on the change and their consumption profile. The overall impact per tariff category is shown in the next table. To be noted is the structural changes are a rebalancing exercise that some tariffs see increases and other reductions, but the overall revenue is the same.

Responses to Stakeholder Questions

A substantial amount of inputs have been provided in the body of the submission that provides motivations and justifications on the fundamental shortcomings in the approach. The comments aim to provide a holistic overview and the majority of comments have previously been shared with NERSA, but have not been adequately addressed.

As a result thereof, it is not possible to capture this in the individual responses to the stakeholder questions. NERSA is advised to consider the comments in its entirety and not just on a line by line basis on responses to the stakeholder questions. The EPDM by NERSA has not evolved as one would expect from consultation to consultation and as a result there is a need to go back to the basic principles, e.g. an understanding of the shortcomings in the current methodology, the legislative framework in which the EPDM is underpinned, the understanding of what a methodology entails etc.

Stakeholder Question Cluster 1

A licensee may not charge a customer any tariff other than that determined or approved by NERSA from time to time as part of its licensing conditions.

a) Stakeholders are requested to comment on the legislative mandate for the determination of tariffs.

b) Stakeholders are requested to also comment on the reverse (ie. unlicenced or registered activities) and how this might impact the application of the EPDM Rules.

c) Stakeholders are also requested to comment on the legal status and fairness of the EPDM Rules and applicability to types of:

i. Licenced activities; and

ii. Unlicenced activities.

<u>Eskom's Response</u>

a) As has been alluded to in the body of the document, NERSAs mandate is clearly articulated in both the ERA and EPP, i.e. "It is the custodian and enforcer for the regulatory framework provided for in the ERA. In essence, this is a quotation from the ERA. Thus, NERSA is required to determine or approve tariffs. It is assumed that NERSA will undertake its mandate in accordance with the law as is outlined in the ERA.

b) Several comments have been made in the document regarding the actual details and workings of the EPDM. As a result, Eskom is unclear on the "*application of the EPDM Rules*". The EPDM rule has been determined to be unimplementable. Thus, it would be difficult to comment on "*unlicenced or registered activities*" being referred to, as the current notion is that it is not even feasible in so far as licensed activities are concerned.

c) A significant amount of detail has been provided in the document that renders the EPDM fundamentally flawed as it does not seem to provide rules or even a methodology. It seems to be still at a concept phase and such its legal standing cannot be assessed. Since the implementability of the EPDM rules has been found to impossible, it could be surmised that it is unfair. NERSA has not demonstrated that these proposed methodology rules are in accordance with the requirements of the ERA and EPP. NERSA has also not indicated as to which existing rules, methodologies, codes and other regulatory requirements are being replaced. It implies that key contradictions occur with certain existing methodologies, rules, codes, etc.

Stakeholder question cluster 2

d) *Stakeholders are requested to comment on Table 1 p8 (of the EPDM Rules), which describes the ESI structure and proposes areas of tariff regulation of licenced activities. Are there other activities that should be tariff regulated? Or, conversely, activities that should not be tariff regulated?*

e) *Comment on the EPDM Rule's objectives.*

Eskom's Response

d) The comments outlined in the body of the document emphasize the importance of working within the prescribes of the current legislative framework. It is envisaged that any changes in the energy landscape within South Africa will be outlined in the proposed amendments to the ERA. Our understanding is that NERSA will then take its que from there. As a result thereof, certain activities are not defined within the existing legislation as licensed activities. Thus it is urged that NERSA kindly correct its proposal and only make reference to legal activities. Eskom does not wish to respond to matters that are not within the current law of the country. It is envisaged that as and when the legislative framework changes, further engagements will take place.Please refer to the section – "*Proposals need to be in line with legislative framework*" etc.

e) As has been outlined in the document, NERSA undertakes its mandate within the ambit of the legislative framework of the ERA and EPP. It is unclear how the objectives of the proposed methodology rules fit within that framework. Key to this is the practical implementation of these proposed methodology and since the implementability of the proposed methodology rules is being questioned, it is not possible to comment on the objectives of the proposed methodology rules. It is also unclear as to the current legislative framework being applied. It does not seem to be aligned to the ERA, nor the EPP. Any changes in the EPDM should follow from changes in the legislative framework and not the other way around.

Stakeholder question cluster 3	
f)	*Comment on the fundamental principle of EPDM of mainly using the efficiency of rated operating capacities in the determination of all tariffs, as opposed to the use of sales or revenues to calculate tariffs.*
g)	*Would you consider this migration to efficiency centred tariffs to be fair and transparent?*
h)	*What challenges do you anticipate in this approach?*
i)	*Comment on whether unbundling of the electricity industry structure is mutually exclusive from unbundling of tariff structure (or not) and why?*

Eskom's Response

f) In previous comments by various stakeholders it was highlighted that the approach being proposed by NERSA is not best practice and is neither feasible nor implementable. It is impossible to undertake to say the least. The following stakeholders, at least, clarified to NERSA during the submission in 2022and/or 2021 that sales volumes are essential in determining any price adjustments:

- Professor Anton Eberhard
- Ms Kay Walsh
- Association of South African Chambers (ASAC)
- NEDLAC
- City Power
- Agri SA
- City of Cape Town
- Eskom

It is unfortunate that NERSA has not provided any response to the submissions made by many stakeholders previously. It would be more productive if robust progress could be made where the input provided by the majority of stakeholders is addressed. The proposed fundamental principle is not understood and thus not supported.

g) The proposed fundamental principle is not understood and is therefore not supported and hence definitely does not lead to fairness and transparency.Ie. NERSA has not provided any process of how this will be undertaken. NERSA has not provided any facts, evidence or experience as to where in the world such an approach has been successfully implemented. Eskom has raised this issue on numerous occasions and no feedback has been provided by NERSA.

h) As has been outlined in the body of the document, the proposals need to be made within the confines of the current legislative framework and also follow best practice. We have previously raised the fact that this concept is not implementable. Many stakeholders have provided contributions in this regard. All the responses have been ignored and NERSA continues to maintain its original (incorrect) positions. Engagement on feedback provided has not happened. NERSA instead indicates that only terminology changes will allow for fundamental flaws to be addressed. This did not materailise This is not the case. The comments made by various stakeholders on fundamental issues cannot merely be reduced to an issue of terminology. This did not materailise.

i) As has been outlined on numerous occasions during consultations on the proposed EPDM, many of the objectives that NERSA is purporting to achieve is best placed in addressing the proposals made by Eskom on the restructuring of the tariffs. The tariff can be unbundled without the unbundling of the industry. If NERSA implemented its existing methodologies, frameworks and applications that have been made (specifically from Eskom), significant progress could have already been made. There is perhaps a need for NERSA to go back to the drawing board and provide an overview of how the existing methodologies are able to support the objectives it hopes to achieve.

Stakeholder question cluster 4

j) *Stakeholder are requested to comment on each of the five steps identified under rule 8.*

k) *Also comment on whether these steps can be expected to set prices that will incorporate of the EPDM principles.*

<u>Eskom's Response</u>

j) NERSA seems to be confusing the concepts of revenue determination methodology and a cost of supply framework as the details in some cases seem to have been duplicated in both areas. It needs to be pointed out that these are the exact same steps that the Cost of supply consultation is referring to. NERSA is in parallel consulting on the review of the cost of supply framework that has been in existence since 2015. Thus, the steps are not new. Eskom has supported these steps in the context of the cost of supply framework. Thus it is proposed that the steps within the context of the cost of supply framework can be implemented immediately. The convolutions being proposed in the methodology rules however, are not supported due to it not being feasible and not being possible to be implemented.

k) The steps in the context of cost of supply framework are implementable. However, in the context of these unimplementable methodology rules, it cannot be commented on. It is very important for all stakeholders and NERSA to ensure that the laws of the country are respected. These proposals on the methodology rules is not within the law of the country. Thus it is urged that NERSA ensures that any proposals are within the law and policies of the country.

Stakeholder question cluster 5
l) *Comment on the Revenue Requirement Methodology as a key component of the EPDM tariff setting methodology.*
m) *Comment on the proposed formula under rule 9(2).*

Eskom's Response

l) NERSA has an internationally recognized revenue determination methodology in the MYPD methodology. The MYPD methodology is within the legal and policy framework of the country. The proposal being made in this proposed methodology rules does not seem to be complete and has not been given thorough attention. The reference to sales volumes is not respected. Thus it is surmised that it is not appropriate. As has been clarified in the document, Nersa must clarify the status of the MYPD in the development of the EPDM. It seems that this one methodology/rules being consulted on, is replacing many NERSA methodologies. Up to now, NERSA required the determination of allowable revenue (efficient cost + fair return) by the MYPD methodology. The revenue is then apportioned to customers in accordance with the NERSA cost to serve framework. The revenue is then translated into various tariffs by the use of the NERSA ERTSA methodology. These approvals determined the prices and price adjustments for various prices including prices to be charged by Eskom to Municipalities. NERSA then made further approvals for the prices to be charged by Municipalities to their customers, using a benchmark approach. This EPDM does not clarify which parts of the current methodology is nb

m) The formula is very scanty and is not appropriate for a methodology rule. It requires further attention. It needs to clear about what the expectations are. Formulas are meant to be very detailed in nature to guide users when making submissions. It is not in accordance with the legislative requirements. It is thus not supported.

Stakeholder question cluster 7
n) *Comment on each key elements of the Revenue Requirement Methodology being a key component of the EPDM tariff setting methodology.*
o) *Comment on the regulatory cost principles outlined in rule 9(4) (a) – (d).*

Eskom's Response

n) Reference must be made to the arguments set forth in the details contained in this submission. Several comments are made that question the fundamentals of the proposed consultation and hence it is not always feasible to provide a comment on the specifics as the overall concept is fundamentally flawed. The EPDM tariff setting methodology is not implementable and thus not possible to comment on the key elements. As mentioned previously, the approach to the revenue requirement is not correct. The sales volume are an essential aspect to be considered. The revenue requirement is not appropriately addressed. It is not in compliance with the ERA and EPP.

o) It is not understood what the purpose of these criteria are. It is not possible to make these determinations at activity level. This area is also contrary to the ERA and EPP requirements

Stakeholder question cluster 8	
p)	*Comment on the consumer data analysis under rule 11.*
q)	*Comment on the use of smart meters.*
r)	*Comment in the collection of consumer demand data for setting tariffs.*
s)	*Comment on how to deal with consumers without smart meters.*

Eskom's Response

p) NERSA is not mandated to consider profitability, competitiveness, and affordability in making price adjustment decisions. This is not a mandate provided to NERSA by the ERA or the EPP. It is not known how NERSA could even consider such an approach. This creates enormous risk to any licensee.

q) The purpose and abilities of smart meters would need to be considered. The cost benefit analysis would need to be considered. The purpose of smart meters needs to be further understood. It should not be the use of smart meters for the sake of. The costs of smart meters fall on consumers. Will the consumers need the level of details being afforded by the smart meters.

r) This is not within NERSA's mandate. It would be an absolutely untenable. The logic of using consumer data to determine price increases is unsustainable. If prices are going to consider affordability, profitability and affordability, then expectations would be created. What happens if the basic requirement of the ERA and EPP are not met. It is likely that gaps would need to be filled. Were would this be sourced. It seems that there would be subsidization from the taxpayer. This has been found to be a non-sustainable approach.

s) Depends on what is going to be done. A cost benefit analysis needs to be undertaken. What would the source of the funding for the smart meters.

Stakeholder question cluster 9	
t)	*Stakeholders are requested to comment on rule 12 regarding the merit order dispatch, specifically the steps applicable in terms of dispatch by the System Operator under 12(2).*
u)	*Comment on any alternative mechanisms to derive efficiency by compensating only for power delivered to the grid based on least cost dispatch.*
v)	*Comment on non-dispatchable generation/non-merit order dispatched generation (e.g. renewable IPPs, rooftop solar) – how should this be accommodated in the model (or not)?*

Eskom's Response

t) NERSA does not acknowledge that Scheduling and Dispatch Rules are in existence. However, it seems that a new proposal is being made. Expectations are being made on the System Operator that are impossible to do. It would be interesting to know where in the world this occurs.

The system operator dispatches in accordance with NERSA's Scheduling and Dispatch rules. This is in accordance with the merit order. It needs to be clarified that the merit order is defined by the variable costs and not the net cost of electricity. It is thus very likely that a generator with the lowest marginal cost (variable) has the highest net cost. It needs to be noted that the basis of determining costs is presently based on the allowable revenue decisions made by NERSA. Due to still migrating towards cost reflectivity, the actual costs are not covered by the revenue determinations. These shortfalls are funded by the fiscus. The expectation that the System Operator will capturing which generator supplied what amount of power and record the duration of supply is unrealistic. The System Operator will call up power plants in merit order to meet the different loads as they come onto the system and record which generators delivered power and how much over the 24-hour period.

These seems to be a dependence on the system operator to provide information on dispatched generators to enable the determination of recovery of costs by licensees. It is unclear how the process will be managed to ensure the recovery of efficient costs by licensees.

Eskom already undertakes merit order dispatch in terms of the NERSA Scheduling and Dispatch rules. It is thus unclear why this merit order dispatch is being introduced as if it does not occur.

u) This is the crux of the unimplementable proposal being made by NERSA. Once the dispatch of energy occurs in accordance with the existing scheduling and dispatch rules, then the generators would need to be compensated. Thus this is managed at the dispatch stage. This is what is occurring presently. What is being requested is impossible and cannot be entertained.

v) Any renewable technology generation is self-dispatch. Thus, it is defined as must-run and cannot be dispatched. The dispatch of renewables is not considered in the merit order – since they are must-run plants due to their nature. Additionally, the marginal cost of any renewable technology is zero. The principle that rather needs to be considered is that merit order is based on marginal cost – where the marginal cost of renewable is zero. This is already in place and what already occurs.

Stakeholder question cluster 10	
w)	*Comment on the consumer tariff build-up shown under rule 13(1).*
x)	*Stakeholders are also requested to comment on the proposed application of the formula under rules 13(2)–13(12).*
y)	*Comment on the back-up options where application cannot be optimally achieved, such as outlined in 13(3) (f).*

Eskom's Response

w) This is impossible. This is not implementable. Eskom has not seen any such approach anywhere in the world, after intensive searches. NERSA has also not provided information on where this approach is being successfully implemented. This request has been made previously.

x) The mechanics of doing this seems to be impossible in a retail pricing environment and contrary to reflecting system marginal cost-based approach. This approach has been proposed and rejected many times in the US and in literature is referred as the "*decomposition*" method, with identified shortcomings. The most important flaw is that those customers that do consume power during the peak period, the marginal costs are higher during those periods, and it lowers costs for the system if there is reduction in the peak periods.

y) It is Eskom's stance that all costs of all generation need to be allocated to all customers in the hours in which they are providing power. This proposed approach will not support renewable energy and will negatively impact customers that want to wheel energy or put up their own generation plant. In addition, any "*baseload*" customers that is considering wheeling or installing own generation will cease to be a base load customer and fall into one of the other load types. It also places major risk for the viability of projects that are currently wheeling or wanting to wheel, as the mechanism to account for the wheeled energy (currently using TOU tariffs) is unknown and not addressed in the methodology.

A key point to be made is that all customer types consume power (to a greater or lesser degree) throughout the day. Thus, they consume power generated by every generation source active in any particular hour.

Customer loads may also show significant variation in their averaged profiles. The averaged profiles are exactly that - averages. The box and whisker plots below indicate the significant variation in hourly demands that occur for each of the customer profiles.

Figure 2: Variations in hourly demand

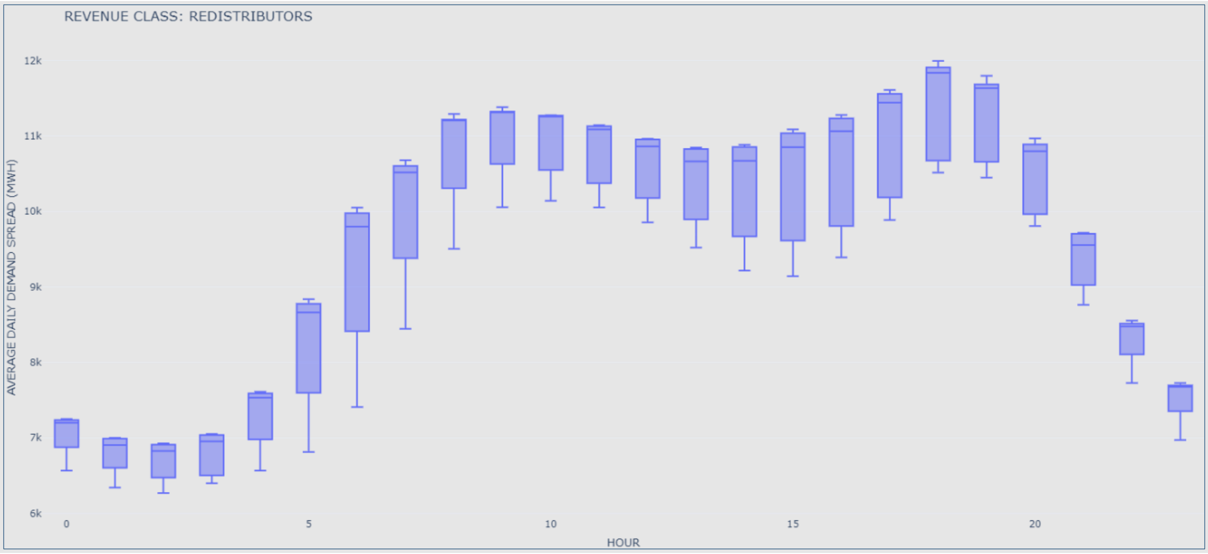
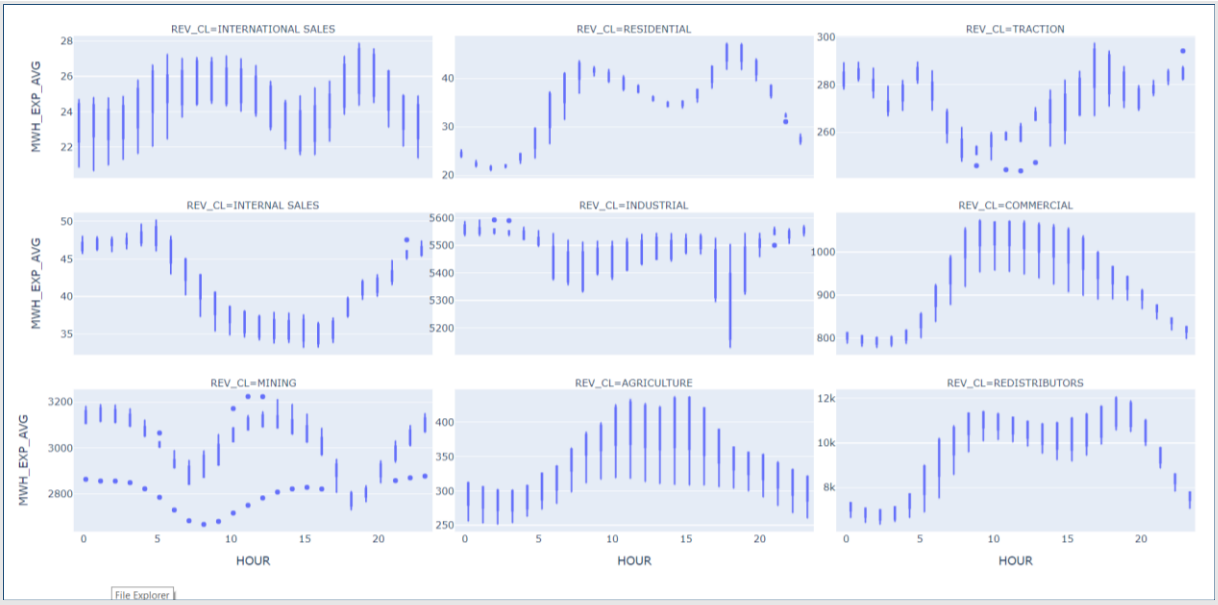


Figure 3: Variations in hourly demands that occur for each of the customer profiles



This level of variation has an impact on the operations, system demands, and marginal costs incurred on any given day. It will thus impact the equitable allocation of these costs to customers.

NERSA's approach to separating into four load types rather than relying on measured hourly load profiles is a simplification of loads that has been used historically in cost allocation and tariff designs, when measurement and data storage technology was more primitive. The approach to defining four generic loads represents a regressive step in cost allocation and tariff design practice. The implementation of this approach would make South Africa unique in that we would be the only jurisdiction moving to less advanced practices rather than modern cost allocation and tariff practices.

These are not representative and far too generic and no customer will perfectly fit into one category at all times. There is also very little difference between Load types, 2, 3 and 4 and it does not clear how, for example, "*emergency*" power usage will be determined. The load types do not align with how dispatching works, that is assuming baseload is dispatched first, or how costs would be allocated under a marginal pricing scheme, where the price payable will be the cost of the most expensive generation in a particular hour, irrespective of whether the customer is load type 1 or load type 4.

These 4 load types also ignore how renewables will play a bigger role in managing the system and that increasingly the concept of "*baseload generation*" will no longer be applicable due to the changing system profile. Further responses on the load type is provided later.

The document does not detail how NERSA plans on allocating the different load types to customers. This in itself is a big challenge since doing the allocation via metering would entail installing meters for every customer, this is not viable or short-term solution. If for example, it would be done by customer declaration, this would open the door for corruption and exploitation of the system. Surveys might not be answered, continuous polling to ensure we understand the various loads customer base would be needed and the issue of how efficient this needs to be considered.

NERSA seems to have confused concepts typically associated with generation (or supply) profiles, with those distribution customer profiles. The 4 load types presented can be easily applied to generation/supply curves, however they do not take into account the variation and nuances associated with distribution consumption.

It is clarified that the parallel consultation that NERSA is undertaking on the review of the cost of supply framework, is likely to yield more meaningful outcomes.

Stakeholder question cluster 11
z) Stakeholders are requested to comment on the data collection rules in rules14(1)–14(5).

<u>Eskom's Response</u>

The information request looks innocuous. However, it is a matter of what NERSA decides to do with this information is of concern. NERSA has acknowledged that it does not have the capacity to deal with this venture. A proposal to use tariffs to determine costs, is of concern.

- The approval of costs and the design of tariffs are two separate and sequential processes. The two are interchangeably used in the NERSA consultation document. Tariffs do not determine the costs; they recover the allowable costs and cannot provide more revenue than that approved by NERSA (in a regulated environment).

- Tariff design is based on, and starts with a revenue determination, thereafter a cost-to-serve (cost-of-supply) allocation of allowed functionalised costs and finally a restructure or introduce new tariffs to reflect updated cost and cost drivers. In the absence of an update or restructure of tariffs, tariff category increases are used for year-on-year adjustments. Municipalities have to develop an interim revenue requirement in order to conduct a cost to supply study.

- Tariffs are therefore not designed based on the average price announced by NERSA, they are an outcome of the regulated cost plus return decision. This decision on regulated cost is a justification of prudent costs and allowable return. Only once the cost plus return decision is known, the revenue and approved volumes are used in a cost-to-serve exercise to allocate these allowed costs and from this tariff are designed. The cost-to-serve is not a cost justification process, it is a cost allocation process for the purposes of determining end-use retail tariffs.

- The Eskom submission to NERSA for the approval of tariff structural changes or new tariffs, is a separate process from the annual tariff adjustment process. This follows that the approval of changes in tariff structures or new tariffs is required before they are adjusted to reflect a new financial year's price level. Further, the NERSA regulation, ERTSA directs the determination of year-on-year tariff category increases requiring that annual increase submissions are exclusive of changes to tariff structures and limits the approval to a change in tariff rate levels through average price increases.

- The steps to determine and design tariffs are well documented internationally as a sequential process.

- The first determines the required level of annual revenue, typically known as the revenue requirement. This determination is crucial in understanding what the holistic, efficient costs including a fair return would be required by the utilities. This is also aligned to NERSA requirements in meeting its mandated role of allowing an efficient licensee to recover its efficient costs and a fair return. There are ample opportunities for NERSA to analyse, benchmark and thereby determine what this should be. It also follows that it is a matter of how NERSA undertakes its role within a defined, internationally recognised set of rules.

- The second phase which is the cost to serve - apportions the revenue requirement using functionalised divisional costs among justifiable and segmented customer categories, using cost drivers such as customer-related costs, demand-related costs and energy-related costs cost to serve

- The third phase where the tariffs or rates, are designed (structures and level) in order to collect the allocated cost from each customer category. This process takes into account, guided by national policy, the Codes and NERSA rules, sophistication of customer needs, metering, affordability, impact of changing from the existing tariffs, revenue risk (departing from the cost driver) and fairness.

Stakeholder question cluster 12	
aa)	*Stakeholders are requested to comment on the tariff application process under rules 15(1)–15(3).*
bb)	*Comment on the content of the tariff application under rule 16.*
cc)	*Comment on tariff consideration and approval under rule 17 to 19.*
dd)	*Comment on the rule regarding non-compliance with the tariff setting procedure under rule 20.*
ee)	*Comment on the rule on the public register of approved tariffs under rules 20 and 21.*

Eskom's Response

aa) This seems to be a description of what is needed by NERSA. The details are not provided. It is unclear how tariffs can be applied for. The link to legislative requirements seems to be missing and is not understood.

bb) This seems to be a description of what is needed by NERSA. The details are not provided. It is unclear how tariffs can be applied for. The link to legislative requirements seems to be missing and is not understood. The request for payment is unclear.

cc) This seems to be a description of what is needed by NERSA. The details are not provided. It is unclear how tariffs can be applied for. The link to legislative requirements seems to be missing and is not understood.

dd) Not enough details are provided. It is unclear how this process will work and what the purpose might be.

ee) The previous comments on the unimplementability of these proposals refer. Thus, it is such tariffs will not be able to be registered, since a sensible implementation is not possible.