Eskom Holdings SOC Ltd Response to:

NERSA'S CONSULTATION PAPER

METHODOLOGY FOR THE DETERMINATION OF TARIFFS AND PRICES IN THE ELECTRICITY INDUSTRY

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Contents

Executive Summary

Key objectives of the methodology can be met by existing methodologies together with implementation of Eskom's Retail Tariff Plan

It has been demonstrated that key implementable objectives of this proposed methodology can be easily 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 (to be submitted to NERSA during 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.

The Eskom retail plan submitted to NERSA in 2020 was a move in the right direction, in particular, reflecting Eskom's unbundled costs, updating tariffs and tariff structures to be more cost-reflective in structure and responding to changing energy environment. It is disheartening that this proposal by Eskom was not considered by NERSA on the basis of a methodology that still needed to be developed and in particular to support the misguided approach to go to type of use tariffs. Eskom will be submitting an updated version of the Retail Tariff Plan to NERSA in August 2022 to restructure Eskom's tariffs. NERSA is obliged to consider the proposals being put forward by Eskom and any further delays in approving this Eskom Retail Tariff Plan, will move the industry backwards, will continue with non-cost-reflective tariffs and create significant price shocks for customers in the future.

The other key benefit is that the country does not have to wait for the realisation of the key implementable objectives – this can be achieved as early as from 1 April 2023. The legislative and regulatory frameworks are respected and are not a cause for concern. Implementation of these known processes allows for incremental migration towards a market. It does not require significant infrastructure investment and allows for NERSA to continue to consult through a robust iterative process that will enrich the proposals and supporting methodologies, rules, guidelines and codes to result in an implementable methodology, within the legal prescripts. The implementation of the existing methodologies allows NERSA to be compliant with the High Court order for FY 2025, where prevailing methodologies together with other regulatory requirements are applicable.

This is the most pragmatic solution for the situation that the country finds itself in. It will provide stability, predictability and allow for progress in the correct direction towards cost reflectivity at a revenue and tariff level, and in tariff structures as well as towards the preparation towards a market.

NERSA must allow for recovery of efficient costs and a fair return

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 :

1) to calculate the amount of the total prudent and efficient costs, for an assumed level of electricity sales thus production volume for the future year (this step is required to give effect to sub-section (a) above);

2) to calculate the amount of the return that would align to the reasonable risk-adjusted weighted average cost of capital – i.e. such amount of return, divided by the average total amount of capital assumed to be employed during the future year, will result in a percentage aligned to the reasonable risk-adjusted %WACC (this step is required to give effect to sub-section (b) above);

3) to then aggregate the amounts calculated in step (1) and step (2) above, resulting in the total amount of required revenue for the future year. There is no means of ensuring adherence to ERA s.15(1)(a) and (b) in any way other than by including this step.

Therefore, it is implied that for a regulator to give effect to the requirement as per ERA s.15(1)(a) and (b), such regulator will have to calculate the total required revenue for the licensed entity.

Revenue requirement determination is essential for ensuring financial sustainability for the licensees i.e. meeting operating and finance costs, and fair return. 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 cannot be guaranteed. It is rather directly linked to the level of prudent and efficient costs.

Eskom Board requires NERSA to determine allowable revenue at an Eskom level to undertake its fiduciary responsibility

A majority of Eskom's business is regulated by NERSA. The Eskom Board's fiduciary responsibility requires it to ensure that Eskom is a viable business and can operate as a going concern. The recoverable revenue, for providing the regulated services, is a key element for the Eskom Board. In addition, the Shareholder, investors, credit rating agencies and lenders will only be able to undertake their roles and provide services to Eskom when the expected revenue for the entity is known. It is understood that a similar requirement is critical for other licensees such as municipalities. It is impossible to undertake any budgeting or planning exercise without knowing what the allowable/ anticipated revenue would be.

Sales volumes are necessary to determine revenue requirement and prices

It has been 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 the sales, and from this the 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.

"*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.

It is obviously inconceivable that the MYPD methodology or NERSA or Eskom or government could 'set' actual sales volumes. Volumes have to be forecast and the actual results are obviously 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. Primary energy cost variances due to lower sales have been included in each of the primary energy cost elements in regulatory clearing account (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.

Sales volumes are necessary to optimally plan for delivery of electricity service

The starting point for Eskom to plan for the delivery of electricity to the country, requires that the sales volumes need to be known. The development of an energy wheel that considers the various supply options, demand requirements and losses guide the production planning process. An important and natural phenomenon of energy losses does not seem to have been considered in this consultation paper. The production plan attempts to balance the supply options with the demand requirements. Any similar utility as Eskom initiates its production planning based on the sales forecast that needs to be met. The sales forecast needs to be known to undertake production planning. This allows for optimal utilisation of resources. Key amongst these is the securing of sufficient primary energy, especially coal. It is essential that availability of coal is optimally sourced to allow for customers' needs for electricity to be planned and met. Coal costs are one of the single highest costs in Eskom's revenue requirement and needs to be optimally addressed. Not knowing the forecasted sales will not facilitate securing of coal supply. Could result in over- supply (with tremendous costs) or under-supply (not being able to generate) – either would be disastrous for electricity customers.

The sequence of the process to determine the price adjustment is unclear

NERSA undertakes to source information from licensees and customers to determine detailed tariffs. The format of the manner in which this information is provided is unknown and yet to be communicated to licensees. Information will need to be provided once in five years, with quarterly or monthly updates for certain changes. The level of detail required for NERSA to determine prudent and efficient costs is scant. It is unclear how NERSA will undertake its prudency assessments, if requirements are not addressed. In many instances, benchmarks are referred to, but not provided as yet. It is assumed that once these are developed by NERSA, they will be consulted on. NERSA will utilise information that it will source from electricity customers to determine their usage patterns. It is unclear what jurisdiction NERSA has over electricity customers. Clarity is required on the recourse available to NERSA if information or correct information is not provided by customers. In depth analysis of this information will contribute to NERSA approvals on any price adjustments. Where direct information is not available (through smart meters), NERSA will apply benchmarks. NERSA will determine levels of affordability, profitability and competiveness to determine the prices. NERSA will then determine the prices for customers. The remainder will be subsidised by the fiscus.

The methodology does not require a formal application of any sort by any licensee. NERSA will utilise the information received from all licensees to make tariff decisions. This indicates that the ability of the licensees to recover efficient costs and a fair return (in compliance with the ERA), is severely at risk.

NERSA has acknowledged that it has limited skills and processes and the development still needs to happen. The actual processes to be undertaken are not transparent, nor is the impact on customers shown. All stakeholders should be able to understand processes to easily replicate decisions to be made. However, the country is required to put its trust in NERSA to translate all the information it has sourced to provide economic regulatory direction and decisions on the price of electricity.

Implementation of tariffs

Phasing-in of the proposed methodology will simply not work. Assuming for a moment that such a methodology was implementable (which Eskom argues in its current form it is not), it cannot be that some parts of the industry, for example Eskom and large municipalities implementing this methodology and others not. This is especially when it comes to the replacement of the wholesale pricing tariffs with the suggested NERSA "WAT" and "load types". This would lead to greater disparity in the industry regarding tariffs. In addition, the "type of use" approach has been identified to have a fatal flaw. Eskom understands that such an approach has not been implemented anywhere in the world.

Moving away from the concept of time of use (TOU), which is in accordance with the Electricity Pricing Policy, to an apparent "type of use" 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, in accordance with NERSA's scheduling and dispatch rules, dispatch generators on a least marginal cost basis already. 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 economics of running a power system seem to be misunderstood in the proposed methodology.

Many customers including those with baseload generation, are considering wheeling energy or installing own generation, and therefore their load profiles will change. The proposed methodology's 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.

Migration to cost reflectivity seems to have been abandoned

NERSA is aware that as far as Eskom's allowable revenue is concerned, a migration towards cost reflectivity is still a journey being undertaken for many years. The key element of allowable revenue that was used to facilitate this journey has been the return on assets (ROA). NERSA has indicated that ROA will be determined at weighted average cost of capital (WACC). This sudden jump will result in a tremendous increase in prices for all customers, since such a radical change is being proposed. The means for migration to cost reflectivity has now been removed.

NERSA to honour court outcomes

NERSA has many court outcomes to implement. Further legal processes are still underway. These are mainly linked to allowable revenue. It is understood that NERSA will honour these requirements.

Requirements for implementable methodology

An implementable methodology should provide very specific direction to all licensees on what is required for its implementation. A methodology cannot be phased in, partially applied, or be transitioned into. It is understood that any NERSA methodology should provide supporting regulatory rules, codes and guidelines that need to be followed by NERSA licensees to achieve the desired outcome. The minimum criteria that need to be met include legislative compliance, alignment with all other NERSA licence conditions, timing requirements, detailed information requirements, scope of which licensees it is applicable to and needs to be well socialised to allow for implementation. All these reviews of methodologies will require consultation in terms of NERSA's legislative compliance – which will take additional time to finalise. Thus, it could be safely assumed that this proposed methodology, and the related regulatory requirements will not be finalised by 30 September 2022.

Proposed methodology requires significant development before finalisation

From the information contained in the document, it is not clearly understood how the responses obtained from the myriad of questions posed will be translated into clear and concise rules and regulations that will serve as the basis for a methodology governing the electricity industry. It can thus be inferred, from the inputs being sought, that there is still a significant amount of work that would still need to be undertaken by NERSA to translate the contents into a workable and implementable methodology that can properly guide licensees in complying with NERSA's requirements and to provide customers with the required information as to how this will impact their tariffs. It is evident that the proposed methodology would require a number of iterations before completion. There are many areas where it has been indicated that NERSA has or will develop further details. It may also be necessary to further critically evaluate comments that have been provided to the consultation on the principles to determine a new price determination methodology, as was undertaken during 2021. In addition, the dependent regulatory guidelines, frameworks, methodologies, etc will need to be reviewed. This also requires further consultation on these dependencies, prior to finalisation. NERSA would benefit tremendously by additionally getting contributions on this proposed methodology from appropriate consultants. NERSA is urged to provide details on where this proposed methodology has successfully been implemented (if at all). It would not be appropriate for NERSA to open itself up for a judicial review due to it not undertaking the requirements in accordance with its mandate sourced from the relevant legislation. It is urged that careful consideration be given to the time required to prepare all licensees for the implementation. Licensees will likely need to develop systems and processes, will require implementation of infrastructure and employ many more people to meet the proposed requirements.

Clarity is required on which methodologies and frameworks are being replaced

It seems that this one methodology being consulted on, may replace many NERSA methodologies. Presently, NERSA requires the determination of allowable revenue by the MYPD methodology; apportionment to customers in accordance with the cost to serve framework; and then translation into various tariffs by ERTSA methodology. NERSA then made further approvals for the prices to be charged by Municipalities using a benchmark approach. Further related regulatory requirements have dependencies. All licensees are bound by the requirements of the methodologies and Codes, and these would have to be revised first before any NERSA approved methodology is published and be applicable.

Clarity is needed on timing and format of implementation of methodology

The timing of implementation of the methodology requires clarity. Indications are that NERSA wishes to finalise an implementable methodology together with related regulatory requirements by 30 September 2022. It is clear that this will not be possible due to significant areas of incompleteness. It seems that NERSA is attempting to accelerate the finalisation of this methodology to meet the 30 September 2022 deadline imposed by the High Court Order for the determination of the FY 2025 revenue determination applicable to Eskom. The order specifically requires a complete methodology as well finalisation of all related regulatory requirements. These are not possible for this proposed methodology to be finalised, by 30 September 2022, since they seem to still require various steps to be undertaken including further development of aspects of this methodology, relevant Government policy decisions and require further consultation on aspects that are incomplete in this consultation document. In the absence of this methodology being finalised by 30 September 2022, the prevailing methodologies will apply.

A methodology cannot be partially implemented, implemented on licensees that can implement or allow for transitional arrangements that are not part of the methodology.

Additional generating capacity in South Africa is being addressed

It is submitted that ensuring that additional capacity be made available in South Africa is an urgent priority that the country is addressing right now. It is understood that the Presidency with other Government Departments and stakeholders are addressing this critical matter. It is referred to ensuring "MW on the system". It is clarified that this consultation paper on the proposed methodology does not address this aspect. It is submitted that this is out of scope of this propose methodology

Legislative and policy requirements must be met

NERSA acknowledges that changes in the regulatory approach can only occur **within the legislative framework**. However, this statement is contradicted in many instances. Certain regulatory proposals are made that contradict the Electricity Regulation Act (ERA), the Electricity Pricing Policy (EPP) or other NERSA codes and regulatory frameworks. The ERA requirement where 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 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. Establishment of entities such as the central purchasing agency that should house the IPP Office (according to this proposal) amongst others is being consulted on by the DMRE. The National Energy Regulator Act (NERA) and Promotion of Access to Justice Act (PAJA) guides NERSA in the process towards making any decision. This is extremely important to allow all stakeholders opportunities to engage on further developments of the as yet incomplete methodology as well related regulatory requirements. This consultation process seems to be creating policies on behalf of Government that severely impact the fiscus by assuming further subsidisation of electricity customers based on information provided by the same customers. Consequential legislative impacts have not been considered. The Minister of Public Enterprises will not be able to meet the requirements of the Municipal Finance Management Act (MFMA), due Eskom not requiring to make a revenue application to NERSA any longer. NERSA will need to correct such possible violations of legislation before it finalises this proposed methodology.

Impact of proposed methodology to be determined prior to finalisation

One of the greatest concerns with the proposed methodology is there is no discussion or analysis provided of the impacts on customers, nor any tools provided where customers (including Eskom Distribution and municipalities) could analyse such impacts so that better informed comments could be made. It is impossible to work out what such impacts would be due to the many questions that remain unanswered in the document. It can be inferred that if these proposals were implementable, then industrial customers will be favoured over other categories of customers (mainly residential customers).

Cost benefit analysis of price determination process

This consultation paper depends on very detailed and far-reaching information requirements, significant update in infrastructure (smart meters), support processes (to address data) and additional skilled people. It is recommended that a cost benefit analysis be undertaken to determine the viability of such a process before finalising. It would be optimal to ensure that limited resources in this country be used where they best add value. As an example, a conservative estimate of installing smart meters for Eskom customers will cost in the region of R15bn. More viable alternatives may need to be considered.

Implementation of Retail tariff plan from FY 2024

Eskom is proposing a change to tariffs structures for implementation from 1 April 2023. The aim of which is to unbundle tariffs to reflect divisional costs while preparing for legal separation. Delays in approving the retail tariffs plan will have serious consequences for Eskom and for customers. There is some alignment between the proposed Retail Tariff Plan (for example, unbundling) and this NERSA proposal, with the major area of difference being that Eskom will continue with time of use tariffs (in accordance with the policy direction provided by the EPP).

The Eskom Retail Tariff Plan is also aligned to what is enshrined in the EPP. Load factor types will place significant complexity in retail tariff design, ignores the way a power system works, will penalise low load factor and peak users significantly more than is done with TOU tariffs. This is seen as a backward step, whereas the Retail Tariff Plan is a forward-looking plan. This is particularly due to the changing energy environment and for Eskom and municipal licensees to be enable proper cost-recovery and appropriate pricing signals.

Impact on customers and licensees

There is no analyses or even assumptions provided by NERSA on the impact on customers or licensees. It is impossible to assess what the NERSA methodology will mean in practice or how this will be implementable.

Conclusion

Arising out of the challenges and risks identified, it is proposed that all stakeholders be encouraged to continue to participate in NERSA consultation processes through various iterations to further develop the methodology. It is also recommended that NERSA make an assessment whether it wishes to await the amendments to the ERA and EPP prior to finalising the methodology. Whatever approach is adopted will still allow for much more work to be done on developing an implementable methodology. It is urged for NERSA to genuinely engage on comments and responses provided to allow for robust engagement for the enrichment of the methodology. It is essential to ensure that the proposed methodology is compliant with prevailing legislation and Government policies. It is essential for the methodology to be implementable. This may require a revisit on how the objectives can be met. It is evident that this approach is dependent on vast amount of information. The iterative process will accommodate a sharpening on the focus of information that is available and processes that need to be undertaken to source the information. This will all contribute towards the implementation of the methodology, when the time arrives. The time will also provide for any reviews of related methodologies, codes and guidelines – as may be required. Other policy issues, such as subsidies will require engagement with relevant Government authorities.

A cost of serve methodology has been the basis of regulating utilities (not only electricity) for decades. It is a globally accepted methodology that has stood the test of time. It is submitted that such a methodology can never be outdated. Our experience in South Africa, has not been due to challenges with the methodology, but the manner in which NERSA has applied the methodology. A summary of regulatory models all being based on a cost of serve methodology has been illustrated to provide a context to NERSA as it finalises this methodology.

In the interim while awaiting finalisation of methodology, it is proposed that the country continue to employ prevailing methodologies to migrate towards cost reflectivity at revenue and tariff level. It is critical to implement Eskom's Retail Tariff Plan in FY 2024 to allow for further unbundling and cost reflectivity at tariff level.

1 Context and Framework for Methodology

1.1 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 methodology must be aligned to all other NERSA regulatory requirements and NERSA licenses. It should not create any areas of contradiction
- 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 a methodology does not seem to meet these minimum requirements. It is for these reasons that the following proposal to follow a more robust, iterative process prior to finalisation of the methodology for the benefit of the country is being proposed. Guidance is provided to NERSA in this response on aspects to be considered as it finalises this methodology.

1.2 Proposed approach to finalisation of Electricity Price Determination Methodology

It is evident that NERSA is still requesting significant contributions from stakeholders on many areas that require clarity. It is noted that this consultation is not on a complete methodology, but a further 'fleshing out of details' of the proposed principles approved earlier this year. It is evident that the proposed methodology would require a number of iterations before completion. There are many areas where it has been indicated that NERSA has or will develop further details. These will need to be consulted on, prior to finalisation of the methodology. Included in the subsequent sections of this response, Eskom will indicate where further aspects of the methodology are critical – thus requiring further consultation. It is submitted that this is a significant change from the existing suite of methodologies that the consultation paper is possibly replacing. It is evident that further rounds of consultation are necessary before the electricity price determination methodology can be finalised. This would require updated drafts for further stakeholder consultation, once this consultation has provided an opportunity to enrich the next update. It is urged that NERSA meaningfully consider the input that will be provided to enrich the process towards the finalisation of the methodology.

It may also be necessary to further critically evaluate comments that have been provided to the consultation on the principles to determine a new price determination methodology, as was undertaken during 2021. It seems that detailed responses provided by stakeholders during the consultation on the principles were not taken on-board, as this consultation paper on the proposed methodology has maintained the original approach.

In addition, the dependent regulatory guidelines, frameworks, methodologies, etc. will need to be reviewed. This also requires further consultation on these dependencies, prior to finalisation.

It is submitted that NERSA would benefit tremendously by additionally getting contributions on this proposed methodology from appropriate local and/or international consultants and experts in this field. 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" tariffs has been implemented. 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.

It would not be appropriate for NERSA to open itself up for a judicial review due to it not undertaking the requirements in accordance with its mandate sourced from the relevant legislation. This will likely cause further delays for NERSA in undertaking its mandate.

It must be recognised that such a significant review of price determination methodologies take time and require many rounds of consultation. It is unlikely that just one round will allow for the finalisation of such a complex matter. This has been alluded to by many stakeholders in the consultation on the principles, undertaken during 2021.

The list of stakeholders that made reference to the need for long, thorough and/or iterative process include the following:

- South African Local Government Association (SALGA)
- Professor Anton Eberhard
- Eskom
- Dr Grove Steyn, Meridian, Economics
- Agri – Limpopo
- City Power
- Agri South Africa
- Energy intensive User Group (EIUG)
- Operation Vulindlela
- The Association of South African Chambers
- Business Unity – South Africa (BUSA)
- Organisation against tax abuse (OUTA)

It is not clear from this consultation, how the matters of concern raised above, were taken into account. It is thus further re-iterated that once this initial round of consultation has occurred, further rounds be undertaken. This will allow time for various participants to be in a position to positively and meaningfully influence a methodology that is fit for purpose, can be implemented and achieves the objectives of the ERA and EPP. It will also allow to for analysis, review and finalisation of the dependent regulatory requirements for the industry. Additionally, it is understood that key groupings of licensees were not able to meaningfully engage on this consultation due to the limited time afforded to stakeholders.

It is further clarified that the High Court order related to the review of NERSA's decision to reject Eskom's MYPD 5 application is clear that the prevailing methodology together with related regulatory requirements will be applicable for FY 2025. If this methodology (being consulted on) together with the related requirements have not been finalised, then they will not be applicable. In addition, the Court order requires a revenue application to be made by Eskom. This proposed methodology does not require a revenue application. It can thus be concluded that timeous decisions by 30 September 2022 will not be made and will not be applicable.

1.3 Consultation paper is not complete

In the consultation paper many references are made to developments yet to be undertaken to complete the methodology. It can thus be inferred that the methodology itself is not being consulted on, but rather a further 'fleshing out of the details' of the proposed principles is being consulted on. It is clarified that most of the criteria for an implementable methodology, as referred above, have not been met. Details to substantiate this view are provided in each of the sections.

1.4 Stakeholder comments during consultation on principles to develop a new pricing methodology still require consideration

It is submitted that NERSA has not legitimately considered the responses provided by various stakeholders during the related consultation (in 2021) on the principles to determine this methodology. This necessitates the repetition of many responses in this response. The original Eskom responses provided to the principles document are attached hereto for ease of reference. It is humbly recommended that NERSA revisits the comments made by all stakeholders as similar sentiments were shared by a number of key stakeholders within the industry.

1.5 Consultation timeframe

The following timeframes were indicated in the NERSA reasons for decision (RfD) on principles to determine prices in the electricity supply industry, as approved by the Energy Regulator on 25 November 2021, and published during January 2022.

Table 30: Indicative timelines

Milestone	Start	End
ELS approves consultation paper	23/02/2022	08/03/2022
Public Hearings	20/05/2022	26/05/2022
Final Methodology presented to ELS	15/06/2022	23/06/2022
Final Methodology presented to ER	18/07/2022	28/07/2022
Final methodology successfully Published	01/08/2022	01/08/2022

**Extract from NERSA RfD on principles to determine prices in the electricity supply industry*

However, these indicative timelines were delayed in the first step by 114 days, if it is assumed that the consultation paper was originally going to be published on 8 March 2022. The publishing of the final methodology was indicated for 1 August 2022. This is a period of 146 days from publishing of a consultation paper to publishing of an approved methodology.

Table 1: EPDM Consultation Programme

Task Name	Start	Finish
Revision of Pricing Framework and t methodology (EPDM)	**Mon 22/04/25**	**Fri 22/09/30**
Special ELS approves publication consultation paper	Fri 22/06/24	Fri 22/06/24
Publish on website/Newspaper	Mon 22/06/27	Thu 22/06/30
Public Consultation	**Thu 22/06/30**	**Fri 22/07/29**
Closing date for comments	Fri 22/07/29	Fri 22/07/29
Public Hearings	Thu 22/08/04	Wed 22/08/10
ER Decision on the Final Methodology	**Fri 22/08/26**	**Thu 22/09/29**
Final Methodology presented to Extended ELS	Fri 22/08/26	Mon 22/09/05
Final Methodology presented to ER - scheduled ER	Thu 22/09/22	Thu 22/09/29
Successfully published	Fri 22/09/30	Fri 22/09/30

**Extract from NERSA EPDM Consultation Paper*

The table above indicates the timeline included in the published methodology consultation paper. The indicated date for publishing the consultation paper was delayed by 8 days. The time from publishing (30 June 2022) to publishing of final methodology (30 September 2022) is 92 days.

These timelines indicate that NERSA seems to be further compromising on allowing for a robust consultation process to allow stakeholders to engage on a significant change in a methodology.

As indicated in Eskom's responses to NERSA's consultation paper on the principles to determine a new pricing methodology, the following table indicate the timeframes and processes undertaken for the finalisation of certain methodologies and manuals. It needs to be pointed out that the MYPD methodologies being reviewed addressed incremental changes. They did not require a significant change in any supporting regulatory methodologies, guidelines and codes and even under these circumstances, the earliest time for conclusion was 7months, a significant deviation from the NERSA proposed timeline of 92 days for a complete overhaul. Hence it is respectfully cautioned that such undertakings would severely negatively impact the electricity industry at large. The industry is already finding itself in a challenging environment and such an overhaul would further contribute to its demise.

Table 1: Consultation Timelines – Selected Regulatory Determinations

NERSA - Review of MYPD Methodology (2011-2012)	NERSA Review of MYPD Methodology (2016)	Guidelines for Prudency Assessment (2017-2018)	Development of Regulatory Reporting Manuals (2007-2008)
Consultation Paper published 14 October, 2011	Consultation Paper published 15 April 2016 for comment.	Discussion Document published for comment 18th December 2017	Review of global best practice 24th April through 30th May 2007.
Second consultation paper published 4th Sept. 2012	Public hearing 2 June 2016	Extension for comments to 31st Jan. 2018	Workshops with key stakeholders July - November 2007.

NERSA - Review of MYPD Methodology (2011-2012)	NERSA Review of MYPD Methodology (2016)	Guidelines for Prudency Assessment (2017-2018)	Development of Regulatory Reporting Manuals (2007-2008)
Public hearing held 1st November 2012	Draft decision published 8 September 2016	Public hearing held on 1st March 2018.	Draft RRM published 19th October 2007.
	2nd public hearing 30th September 2016		Stakeholder workshop 23rd November 2007
Approved 29th November 2012 Published November 2012	Approved 30th October 2016 Published November 2016	Approved 29th August 2018. Published August 2018.	Approved 31st July 2008 Effective 1 Sept. 2008.
Elapsed time * **14 months**	Elapsed time* **7 months**	Elapsed time* **20 months**	Elapsed time* **17 months**

** Consultation Paper to Final Determination.*

1.6 Unclear on which methodologies and frameworks are being replaced

It seems that this one methodology 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.

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

- Cost of Supply Framework for Licensed Electricity Distributors in South Africa
- 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 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.

1.7 Unclear on timing requirements for implementation of methodology

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 30 September 2022. It is clear that this will not be possible. The reasons for this have been provided in many other areas of this response document.

It seems to be indicated that NERSA is attempting to accelerate the finalisation of this methodology to meet the 30 September 2022 deadline imposed by the High Court Order for the determination of the FY 2025 revenue determination applicable to Eskom. However, it is clarified that the timeframe proposed for the finalisation of this methodology will not meet the requirements of the High Court Order. The order specifically requires a complete methodology as well finalisation of all related regulatory requirements. These are not possible to finalise before 30 September 2022, since they seem to still require various steps to be undertaken including further development of aspects of this methodology, relevant Government policy decisions and require further consultation on aspects that are incomplete in this consultation document.

The extract of the relevant section of the High Court order related to the applicable methodology for the determination of allowable revenue for FY 2024 and FY 2025 is included in the section dealing with NERSA court ordered commitments.

It is understood that the implementation of this methodology is premised on information to be provided by all licensees and all customers. The licensee information will be based on the systems within the licensees to be able to source the required information. As yet, the detail on the information to be provided is not available. The customer information is premised on the installation of smart meters with the requisite analysis systems. No indication is given on the timing and sequencing of the events for the sourcing and analysis of this information. NERSA will determine affordability, profitability and competitiveness – based on information provided by customers to them. No timing requirements or information requirements have been stipulated.

1.8 Additional Generating Capacity in South Africa is being addressed

It is submitted that ensuring that additional capacity be made available in South Africa is an urgent priority that the country is addressing right now. It is understood that the Presidency with other Government Departments and stakeholders are addressing this critical matter. It is referred to ensuring "MW on the system". It is clarified that this consultation paper on the proposed methodology does not address this aspect. It is submitted that this is out of scope of this propose methodology.

2 Legislative and Policy Framework

2.1 Introduction to Legislative Framework

NERSA acknowledges that changes in the regulatory approach can only occur **within the legislative framework** (S1.1). 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**

Certain 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 possibly NERSA) will be able to meet this legislative requirement. As far as Eskom is concerned, it seems that an application for a price adjustment is not required. The consultation paper seems to indicate that all relevant licensees will provide NERSA with information. This information will be used for NERSA to make a price adjustment decision. It is also understood that each customer will have a determination that suits its particular situation. As referred to previously, these aspects of the proposed methodology will require intensive consultation. 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 revenue determination methodology 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 consult 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. The list is too numerous to provide an exhaustive list, however a few areas are highlighted here.

- The workbooks requiring licensee information

- The templates requiring licensee information
- The format of the manner in which this information is provided is yet to be communicated to licensees. Format of information to be provided
- Benchmarks to be applied to determine permissible revenue
- Understanding of the third step of the determination process
- Details on the requirements for quarterly adjustments
- Clarification on the legal basis of this consultation paper within prevailing legislation
- How dependence on other Government Departments has been finalised
- How licensees can meet their legislative requirements including requirements in terms of the MFMA, Government Support Framework Agreement (GSFA), the ERA
- How licensees will be in a position to manage their businesses in understanding the recovery of efficient costs, be able to procure resources, etc
- Infrastructure implementation requirements, such as implementation of smart meters
- Impact of implementation of this proposed methodology on licensees, customers, Government. Economy, etc

- **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 made through the retail tariff plan. 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. It could be interpreted that what seems to be the case is that certain customers that are considered to be industrial customers seem to be 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.

2.2 Proposed policy matters related to the ERA

NERSA is consulting on a proposal for the positioning of the IPP Office that is presently reporting to the DMRE. It is proposed that the IPP Office become part of the Central Purchasing Office (CPA) (S 6.1.3.7). It is understood that this is the mandate of the Minister of DMRE and has been consulted on through the ERA amendment consultation earlier this year. It would not be correct for a regulatory consultation process to step into the role of the policy Ministry.

NERSA refers to the potential elimination of the need for negotiated pricing agreements (NPAs). However, the EPP and the DMRE approved framework refers to policy decisions on the need for NPAs. In fact, from the concerns raised by NERSA in the consultation paper in so far as industrial customers are concerned, it would suggest that there is still merit for these NPA's.

NERSA refers to certain separation of activities such as the CPA, Independent System Operator, Market Operator, etc. However, it is understood that the draft ERA is still being finalised in this regard. It would not be appropriate for licensees to provide information in the manner in which NERSA will require if not aligned with the legislative framework. In addition, it is recognised that NERSA is still putting this information together for the next stages of consultation, as NERSA always undertakes in compliance with the National Energy Regulator Act (NERA).

2.3 Other related policy matters that have been proposed

In addition to the policy matters related to the ERA, in this consultation paper, NERSA seems to be proposing certain other policy proposals.

- **Subsidies by the fiscus**

This consultation paper creates the impression that room for subsidies by the fiscus is available and a request can be made for such through the "*Social Welfare Services*" or the "*relevant industrial policy Ministry*". (S 7.3.5 and S 7.3.6)

"Designing subsidy regimes will benefit from the sophisticated approach to setting consumer tariffs. In future subsidies will be determined by the difference between the cost reflective prices and what consumers can prove is the competitive or affordable price for business and households respectively." (S8.4.12. 6)

This is contrary to already existing policy decisions referred to in the EPP. In addition to the policy decision with regards to the negotiated pricing agreements (NPAs), the DMRE has a framework for long-term and short-term NPAs that NERSA is implementing. For the good order of this consultation process on a methodology, it is appropriate for the methodology to be within the policy and legislative framework of the country.

2.4 Proposed Customer Focus

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

"The overhaul also needs to consider the fundamental paradigm shift towards a more consumer-focused approach that balances the needs and drivers of demand to ensure rational and sustainable supply side investments and goes to the heart of the role of an economic regulator." (S1.1).

"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." (S1.2)

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 consultation on the principles (during 2021). It is thus urged that the required attention be given to this compliance.

3 Recovery of efficient cost and a fair return

3.1 Eskom Board must know the NERSA allowable revenue to undertake its fiduciary responsibility

A majority of Eskom's business is regulated by NERSA. The Eskom Board's fiduciary responsibility requires it to ensure that Eskom is a viable business and can operate as a going concern. The recoverable revenue, for providing the regulated services, is a key element for the Eskom Board. In addition, the Shareholder, investors, credit rating agencies and lenders will only be able to undertake their roles and provide services to Eskom when the expected revenue for the entity is known. It is understood that a similar requirement is critical for other licensees such as municipalities. It is impossible to undertake any budgeting or planning exercise without knowing what the allowable/ anticipated revenue would be.

3.2 Determination of revenue requirement at Eskom level is essential

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 thus production volume for the future year (this step is required to give effect to sub-section (a) above);

- to calculate the amount of the return that would align to the reasonable risk-adjusted weighted average cost of capital – i.e. such amount of return, divided by the average total amount of capital assumed to be employed during the future year, will result in a percentage aligned to the reasonable risk-adjusted %WACC (this step is required to give effect to sub-section (b) above);

- to then aggregate the amounts calculated in step (1) and step (2) above, resulting in the total amount of required revenue for the future year. There is no means of ensuring adherence to ERA s.15(1)(a) and (b) in any way other than by including this step.

Therefore, it is implied that for a regulator to give effect to the requirement as per ERA s.15(1)(a) and (b), such regulator will have to calculate the total required revenue.

However, neither the regulator nor the regulated utility has control over the future year's sales volumes, this being mainly a function of national economic activity and growth, structural adjustments in the macro-economy, global commodity prices that drive demand for local minerals thus mining activity, the weather (in terms of temperatures as well as rainfall), etc. If the regulator under-estimates the future year's sales volumes, it will also under-estimate the future year's quantum of fuel and thus costs incurred by the utility. At the same time, it will have divided the fixed, sunk and unavoidable costs (which are not responsive to production volumes) by a smaller amount of sales, thus resulting in a higher average unit-tariff, even though the fuel costs would have been under-estimated. In this situation, through having used such unnecessarily high average unit-tariffs as determined by the regulator, the regulated utility would make a 'windfall' financial gain at the cost of the end consumer, without having taken any management action to 'deserve' such.

Conversely, if the regulator had incorrectly over-estimated the future year's sales volumes in its process of determination of tariffs the regulated utility would make a 'windfall' financial loss, without the regulated utility having had any control over the actual sales volumes which are largely a function of national economic activity and growth, structural adjustments in the macro-economy, global commodity prices that drive demand for local minerals thus mining activity, the weather (in terms of temperatures as well as rainfall), etc.

Either of these outcomes are unacceptable and unsustainable – if tariffs are unnecessarily high due to the regulator's incorrect under-estimation of future sales volumes the economy would pay an inflated price and the utility would make unjustifiably high profits, which is also not in adherence to ERA s.15(1)(a) and(b). Conversely if tariffs are unnecessarily low due to the regulator's incorrect over-estimation of future sales volumes the utility would make unjustifiable losses and be in a situation of not having sufficient revenue to cover its prudent and efficient costs – with all of the negative consequences such as under-maintenance thus unreliable plant thus inadequate and unreliable electricity supply. This situation too is not in adherence to ERA s.15(1)(a) and(b).

The mechanism to both incentivise more accurate estimates of future, as well as to correct for inaccuracies in estimates of an element that by definition is in neither the regulated utility nor the regulator's control, is to allow for a retrospective re-measurement of actual outcome and to make adjustments accordingly.

The only way such a mechanism could be implemented is by using 'revenue' as the core of the regulatory framework. This is because the over- or under-statement of tariffs (relative to total prudent and efficient costs) can only be quantified by reducing the tariff-based regulatory decision to that of total revenue, which is then compared to the total prudent and efficient costs. This then also provides a mechanism to implement the correction – simply by measuring the amount of revenue shortfall or over-recovery, and adding or deducting from a future year's revenue. This 'adjusted revenue' as determined for a future year is then used to set the tariffs for such year, which means that the full under- or over-recovery is corrected for. This assurance of correction in future also serves as a dis-incentive on either party to deliberately over- or under-estimate a future year's sales volumes. Furthermore, such a mechanism serves as a 'risk mitigation' purpose and is a key aspect that is looked for in a regulatory framework by credit rating agencies when it assesses the credit risk of a regulated utility – considering that the regulatory framework constitutes 50% of the total credit risk assessment of a regulated electric utility.

It is often misunderstood that the revenue of utilities is "guaranteed". This is not the case. The 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 cannot be guaranteed. It is rather directly linked to the level of prudent and efficient costs.

Therefore, the reasons for ensuring the concept of 'revenue' is:

a) The type of legal requirement as set out in s.15(1)(a) and (b) is common to all sound regulatory legislation world-wide. For a regulator to be able to give effect to this requirement it would have to determine the total revenue required to cover the full efficient cost plus reasonable, risk-adjusted return. There is no other means of demonstrating adherence to this legal requirement. Adherence to this requirement cannot be demonstrated through a tariff alone.

b) In addition, there is not one electricity tariff but many – as well as demand charges etc. This makes it even more impossible to demonstrate adherence to these legal requirements by virtue of tariffs alone.

However, this consultation paper is completely moving away from ensuring that the licensees must recover efficient costs and a fair return. 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.

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

This consultation paper refers to a "*guaranteed revenue*". The following statement is also made "*In regulatory terms 'allowed revenue' or 'revenue requirement' is not a promise but an opportunity to earn the revenue while revenue regulation implies an expressed promise to provide the estimated revenues to a licensee*." (S1.4).

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.

3.4 Purpose of the regulatory clearing account

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.

3.5 Revenue determinations are central to price determinations (Corrections in the consultation paper Footnote 1, page 12)

"Only the incumbent and dominant player, Eskom, felt the regulation of revenue should be maintained, most stakeholders commented that stable prices and price path, using a metric other than revenue/ sales, would be better. In most other jurisdictions, regulators conventionally apply CPIX calculations to set the price path."

This statement is factually incorrect. Other stakeholders that supported the continuation of the MYPD methodology, as published in 2016 include:

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

It is further clarified that a cost of service methodology, which includes the MYPD methodology is internationally recognised as appropriate for jurisdictions like South Africa. It is necessary for NERSA to consider the viability of the stage that South Africa is in, prior to making changes. The best way to determine the prudency and efficiency is to focus on the costs being incurred. This is thus linked to the determination of efficient revenue.

3.6 Sales volumes are necessary to determine revenue requirement and prices

This consultation paper moves away from the concept of using sales or production for the translation of permissible revenue to determine tariffs. It can be inferred that the prices will be determined based on capacity. For generation, it seems that the usable or nominal capacity of the power station (in MW). For transmission it would the transmission network costs, central purchasing costs, independent system operator costs and market operator costs. Once these costs are known, will be translated into transmission use of system costs and wheeling costs. The distribution wires and retail costs will result in distribution related tariffs.

Reference is made to the REIPP programme in this instance. However, it is understood that the tariff that the REIPP programme tariffs are determined based on energy provided. This is in the format of c/kWh. Thus, REIPP projects are paid in accordance with energy (sales) to Eskom.

As provided in the NERSA consultation paper on principles for the determination of the price determination methodology, the following explanation of the needs for sales is still relevant.

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.

"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.

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 is 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 determined 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. This will impact low load factor customers the most. The likely outcome would be a substantial increase in prices. 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.

During the NERSA consultation on the principles to determine a new price determination methodology, the following stakeholders referred to the need for sales volume to indicate what the average price increase would be. This is a matter for communication and not all customers will see this average price increase.

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

3.6.1 Sales forecasting approach

The approach followed by Eskom in determining the forecasted sales is in line with ensuring that detailed information as possible is considered. Detailed information in many instances is sourced from the relevant customers. Any projected increase or decrease in sales is thoroughly considered. There are various different influences on customers' current and future electricity consumption determined by individual customers' need for electricity and substitutes to taking supply from Eskom. To practically capture this complex dynamic, the Eskom forecasting encapsulates differing sales assumptions by customer types that are the high sales and lower-sales end users. For high-sales volume customers, the sales forecasting assumptions comprises individual customer planning inputs. For the lower consumption customers, the sales forecast is informed by historical trends, weather and relevant economic indicators.

Consequently, volume changes in the high-sales customer category requires the application of an individual bottom-up approach, so as to consider specific sales drivers that include individual business plans, responses to price elasticity of demand (if any), commodity prices, and the consideration of external economic factors.

Municipalities purchase in bulk from Eskom, distributing to industrial and commercial sectors with a greater part of supply to residential end users. Eskom bulk sales to municipalities differ from one municipality (or metro) to the next, as each municipality's purchase profile shaped by their individual customer-mix. Eskom therefore uses a combination of forecasting methodologies combining an individual consultation with the municipality, in line with the respective local government development plans, as Municipalities there are various aspects that impact their respective electricity consumption profiles.

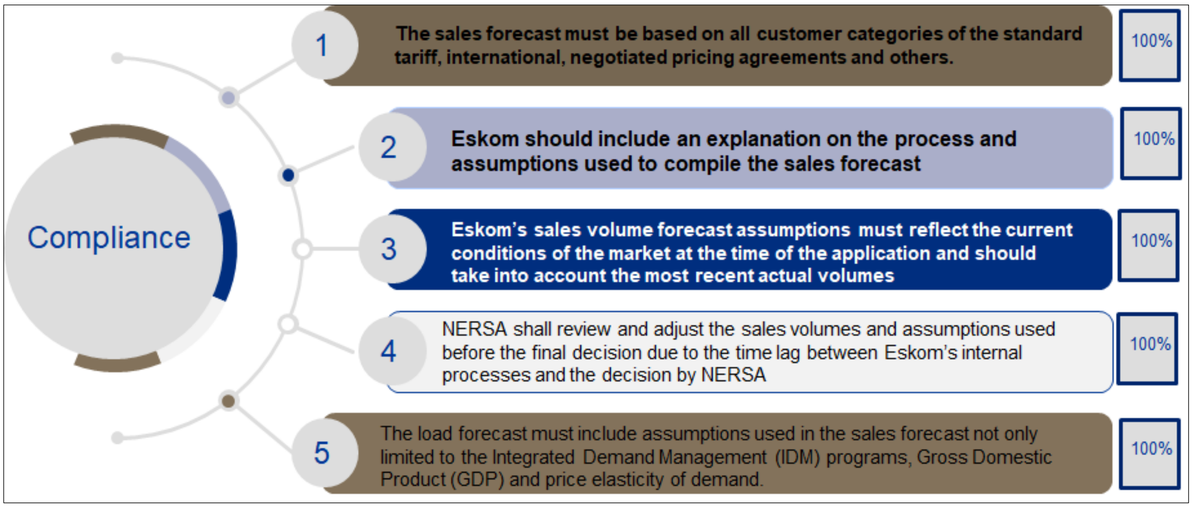
For the residential and commercial sectors, historical trends, weather and economic indicators are the primary indicators that inform the sales forecast.

3.6.2 Sales forecasting process

A five-step process, as depicted in the figure below, is followed to forecast Eskom electricity sales. This process includes the compilation of a detailed forecast using trends per sector. As the diagram depicts the Sales forecast is a bottom up derived forecast.

Each of the Eskom provincial operating units concentrate on their top customers in detail while the other customer sectors is forecasted at summary level to derive a 6 year projection per month with a further 4 years of annual numbers. Detailed analysis and rigorous validation processes follow to ensure consensus that the derived forecast is the most likely scenario given the current information available.

Figure 1: Areas of compliance in providing the MYPD forecasted sales



Each Eskom Distribution operating unit (OU) tend to the customers that account for 80% of that OU's revenue individually in great detail. Engaging the customer executives and obtaining applicable information from the customers while balancing this view with sectoral trends, the expected economic climate and any other relevant information.

3.7 Sales forecasting process geared towards meeting all demand

The sales forecasting as it is undertaken is geared to catering for all electricity requirements including any possible developments and is very reliant on customers providing this information. One-on-one information is sourced from Eskom's individually forecasted larger customers. At the planning stage, all electricity requirements are addressed including that the availability of electricity (or not). It should be noted that during the forecasting process, larger customer are contractually required to indicate their requirements for the forecasting period. Thus, it cannot be assumed that if further electricity is made available, industries will automatically be able to consume more electricity and produce more goods. As alluded above, the ability to undertake production activities, industries need to consider a myriad of factors. There have been instances where customers have indicated that even if the electricity was free, they will still operate in another country due to other challenges being experienced. Energy intensive operations are also becoming more efficient with improving technology choices and it is a worldwide trend that consumption is reducing or slowing down.

3.8 Sales forecast are dependent on various economic factors

For the increase in sales volumes, various economic factors need to be in place. In addition, the country must be in a position to supply the required energy.

3.8.1 Sustainability of industry in SA

There are various factors influencing and affecting the SA industrial sector and consequently affecting Eskom's electricity sales to these customers. However, the price of electricity alone is unlikely to reverse the deterioration in the economy; it would require a holistic approach.

3.8.2 Factors affecting the industrial sector

3.9 Clarification of utility death spiral

There is much debate in the South African public and media regarding the phenomenon of the 'electricity utility financial death spiral', and specifically whether it applies to Eskom. Even further, and more concerning, it seems that much of NERSA's motivation for the various changes being proposed to the revenue and price determination methodology depart from an assumption and acceptance of the applicability of this 'electricity utility financial death spiral', to Eskom.

However, an objective and scientific analysis of the phenomenon of 'electricity utility financial death spiral' proves it to be not applicable to Eskom. This also puts in question much of the foundational basis advanced by NERSA for its proposed changes to the revenue and price determination methodology, thus also puts in question the rationality of much of the proposals as well as the entire process.

3.9.1 Main prerequisites for the onset of an 'electricity utility financial death spiral':

One of the main prerequisites for the onset of an 'electricity utility financial death spiral' is 'electricity demand reaching a relatively price elastic zone' – thus, greater than -1.0. Thus, higher prices will cause lower demand and sales volumes. This situation could potentially commence when the substitutes and alternatives become economically viable, compared to grid electricity.

In addition, the price elasticity of electricity demand combined with the ratio of fixed to variable electricity production costs must be such that the utility is in a worse financial position, after a price increase and demand reduction, than before – i.e. the cost that is avoided due to the lower demand, is less than the revenue that is lost due to the lower demand. It further implies an electricity business with high fixed cost and probably sunk cost.

Therefore, the mere occurrence of price elasticity of electricity demand being greater than -1.0 is on its own not a sufficient condition for a financial death spiral to occur – it must be combined with a ratio of fixed to variable electricity production cost that will cause the volume reduction and thus revenue reduction (in response to a price increase) to have the net outcome of worsening the utility's financial position, notwithstanding the resultant avoidance of variable cost. Thus, the greater the proportion of variable and avoidable cost in the electricity production cost structure, the further it requires a price elasticity of demand to be greater than -1.0 in order to trigger the onset of an electricity utility financial death spiral.

3.9.2 Actual situation regarding electricity price elasticity:

Upon observation of the South African situation since 2008, it is apparent that rather steep electricity price increases commenced in 2008 up to 2013. It is also apparent that a rather flat electricity demand pattern applied since around 2013. Superficial analysis might then take this as evidence of high price elasticity of electricity demand.

However, at closer scrutiny a few other dynamics emerge:

- The country reached the limit of its electricity generating capacity in 2008, following which significant effort was devoted to encouraging energy efficiency through South Africa.
- There was a global financial crisis in September 2008.
- The long term commodity super-cycle changed in 2008 and headed south.
- Structural changes in the SA economy that manifests as de-industrialization, less primary extraction, more services etc.
- Environmental awareness.
- The SA economy GDP growth plunged from 5% p.a. that it had maintained for four years up to 2008, to a level of barely 1%, and remained there since.
- Electricity demand which experienced growth at CAGR of 3.15% for 13 years up to 2008, followed the GDP and the commodity cycle south, and also stayed there – helped of course by the lack of electricity generation capacity, and an apparent de-coupling of the SA economy from the rest of the world in terms of growth patterns, since the downturn of 2008.

- These issues might then in turn trigger an income-elasticity response i.e. an electricity demand response due to the *income* of the consumer changing (reducing, in this case) and not due *per se* to the price of electricity.

These issues mentioned above most probably were the dominant factors, to the extent that had they not happened there might well have been a continued growth in electricity demand post 2013, irrespective the electricity price increases since then. Or, had electricity prices not increased at all, there might well have been a flat demand curve in any event since 2013. It is thus premature to conclude that electricity price increases caused the flat demand, or specifically that Eskom price increases (as opposed to municipal electricity prices) caused the flat demand, or that price elasticity of demand is high – let alone that it is greater than -1.0.

The assumption of high price elasticity of electricity demand to Eskom's prices is also not borne out by the consumer behaviour actually observed since 2008. Eskom's average electricity price underwent its most significant annual increases in the period 2008-9 to 2012-13. Over that five-year period the compound average annual rate of electricity price increases amounted to a very significant 24.8% nominal or 17.5% real per year. The electricity demand however increased in each year from 2009-10 to 2011-12. In contrast, the compound average annual rate of price increases for the eight-year period 2013-14 to 2020-21 amounted to only 8.2% nominal or 2.7% real per year, whilst electricity demand decreased at a CAGR of 0.74% per year – which is probably all due to improving energy efficiency in the economy, combined with stagnant GDP growth especially in the energy-intensive sectors.

Note that high price elasticity of electricity demand, or 'electricity demand reaching a relatively price elastic zone', or price elasticity of electricity demand greater than -1.0 is not yet equal to 'electricity utility financial death spiral'. As mentioned above, the price elasticity of electricity demand combined with the ratio of fixed to variable electricity production costs must be such that the electricity utility is in a worse financial position, after an electricity price increase and demand reduction, than before. Furthermore, if the demand does respond to a higher electricity price thus permanently moves to a lower level, then, in addition to the avoided variable cost, it would also be possible (even if after a period of delay) to avoid some of the fixed electricity production cost, and furthermore it would be possible to avoid incurring the total cost of new electricity generation capacity expansion related to the demand that will not materialize. This would then enable the utility's financial situation to sustainably improve by virtue of higher prices, even if demand permanently settles at a lower level, given the long run ability to avoid the total electricity production cost and not only the variable production cost related to the 'non-materializing' demand. It reiterates the points made above that the presence of any level of electricity demand price elasticity is not adequate to trigger an electricity utility financial death spiral – the greater the proportion of variable and avoidable cost in the electricity production cost structure, the further it requires a price elasticity of electricity demand to be greater than -1.0.

Given the variable and avoidable cost in Eskom's cost structure it would require price elasticity of electricity demand of at least -1.3 to neutralize the financial gain from price increases, let alone to cause a deterioration in the financial situation. In contrast, various independent studies of price elasticity of electricity demand in South Africa have put it at between -0.2 to -0.3 on average, with a recent study putting most large sectors below -0.254 and very few up to -0.432.

3.9.3 Actual situation regarding economic viability of substitutes and alternatives:

For high price elasticity of electricity demand of significantly greater than -1.0 to occur it requires substitutes and alternatives to be economically viable, compared to the price of grid electricity. Eskom's current sub-cost-reflective average price of around 138c/kWh (US$ 8.3c/kWh) in FY 2022-23, for the total of four activities namely generation, transmission, distribution and trading (i.e. the purchasing of all electricity output of all IPPs commissioned since REIPPPP Bid Window 1) puts it well below the very lowest end of any international comparison against non-subsidized prices. Eskom's total average price reflective of prudent and efficient cost for the four activities should be approximately 165c/kWh (US$ 9.9c/kWh) – but also this price level would be at the very lowest end of any international comparison, albeit not by the same excessive margin as applies to the current average price of US$ 8.3c/kWh. This implies there would be no cheaper international substitutes and alternatives to Eskom's current sub-cost-reflective, or its cost-reflective average price.

Furthermore, both Eskom's current sub-cost-reflective average price, and also the price reflective of prudent and efficient cost, are well below the full cost of equivalent South African substitutes and alternatives including back-up and storage – which start at approximately 170c/kWh for grid-scale installations as confirmed by the recent RMIPPPP, for a not-quite-equivalent product (this favourable price comparison might not apply in the case of municipal electricity prices, due to 'municipal surcharges', cross-subsidies, etc.). It is also the experience in other countries that, even with grid prices far higher than Eskom's, it is generally not economical to self-generate in a completely grid-independent manner, compared to the price of grid electricity.

3.9.4 Conclusion on utility death spiral

It thus implies that the two main prerequisites for the onset of an 'electricity utility financial death spiral' are absent in the case of Eskom, namely:

- substitutes and alternatives which, compared to grid electricity, are economically viable to the degree to result in high price elasticity of electricity demand;
- no or little variable electricity production costs or ability to avoid costs, including the long-run ability to avoid the total electricity production cost of new electricity generation capacity expansion related to the demand that will not materialize.

Therefore, it is highly unlikely that an Eskom price increase would result in a volume reduction that more than neutralizes the additional revenue from the price increase, after factoring in the proportion of variable and avoidable cost in the cost structure. These sound, credible, objective, scientific and academically rigorous studies expose the popular public misperception and assumption that, to increase Eskom's average tariff from its current sub-cost-reflective level in FY 2022-23 (of around 138c/kWh or US$ 8.3c/kWh) to its cost-reflective level (of around 165c/kWh or US$ 9.9c/kWh) would trigger a self-defeating 'electricity utility financial death spiral', as the myth that, regarding Eskom, it is.

The only way a 'electricity utility financial death spiral' could occur in Eskom's case is if is artificially stimulated. For example:

- by subsidising the off-grid and other types of technologies that would have the effect of making them seem cheaper and thus artificially advancing the parity point vs. grid electricity;
- by under-charging self-generating consumers for the grid connection which in effect provides such consumer with a free or subsidised storage and back-up facility – in effect enabling free-riding (thus, failing to restructure tariffs to reflect the fixed and variable cost dynamics);
- by adding price premiums to the grid electricity, which would have the same effect of artificially advancing the parity point (e.g. municipal surcharges which result in municipal electricity prices much higher than Eskom's, could result in high price elasticity of electricity demand in municipal areas of supply).

However this does not require a change to the revenue and price setting methodology for Eskom, but rather in the way that NERSA regulates municipal electricity prices. It also puts in question much of the foundational basis advanced by NERSA for its proposed changes to the 'MYPD' revenue and other price determination methodologies, thus also puts in question the rationality of much of the proposals as well as the entire process.

3.10 Focus on Ferrochrome industry

The Government through the DMRE has promulgated an interim framework for long-term negotiated pricing agreements (NPA). The objective of the framework is to sustain and grow the South African economy through increased electricity consumption. This is thus the mandate of the DMRE. Applications from relevant ferrochrome companies are in the process of being evaluated prior to submitting to NERSA. Thus, the Government has provided proposals to support such companies. This is in alignment with the requirements of the Electricity Pricing Policy.

3.11 It is unclear how energy losses are accommodated

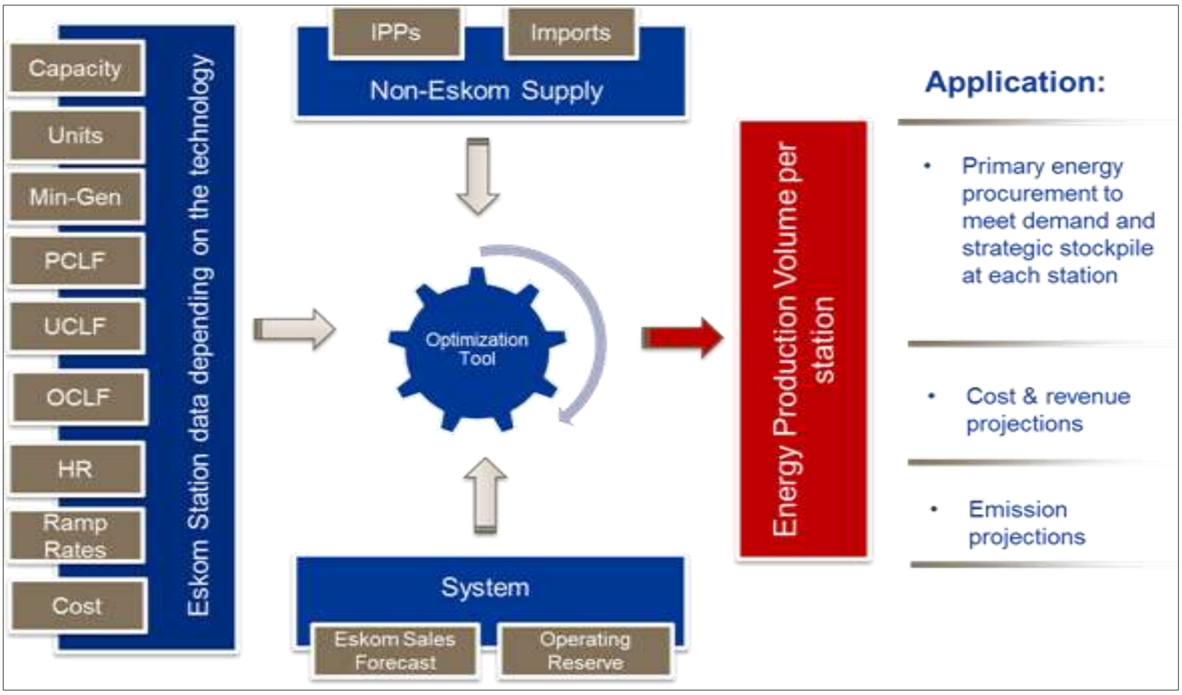
Energy losses is defined as the difference between energy produced (measured at generators) and energy sold to end-use customers. This includes both technical energy losses (also known as copper and iron losses) and non-technical energy losses. It excludes non-payment or bad debt. The NERSA benchmark of 10% as stipulated in the regulators cost to supply framework Section 3.2.1.1 a) (i). The cost of supply framework states that utilities should manage distribution losses within the tolerable range of 5 – 12%. Transmission losses are estimated to be between 2-3%. It is unclear how these technical losses, which are a natural phenomenon, is catered for in this proposed methodology.

3.12 It is unclear how production planning will be undertaken

If the total sales of Eskom are not going to be considered, it is unclear how production planning will be utilised for regulatory purposes. Any similar utility as Eskom initiates its production planning based on the sales forecast that needs to be met. It will not be possible to undertake production planning without planning for a projected sales forecast. Not knowing the sales forecast will not allow for optimal utilisation of resources. Key amongst these is the securing of sufficient primary energy, especially coal. It is essential that availability of coal is optimally sourced to allow for the need of customers for electricity to be planned to be met. Coal costs are one of the single highest costs in Eskom's revenue requirement and needs to be optimally addressed. Not knowing the forecasted sales will not facilitate securing of coal supply. Could result in over- supply (with tremendous costs) or under-supply (not being able to generate) – either would be disastrous for electricity customers.

The following illustrates the production planning undertaken on behalf of the country. The Production Plan is optimised using a simulation tool called the Plexos Simulation Tool.

Figure 2: Overall Production Planning Process



The process for production planning is depicted in the figure above. The inputs to the optimisation tool include hourly demand forecast, planned and unplanned maintenance, ramp rates, variable cost (coal and diesel cost), capacity, number of units per station, minimum generation, operating reserve requirements, commercial operations date for Eskom new build, import capacity, IPPs and all other parameters required for modelling the system.

Generators are dispatched from the lowest variable cost to the most expensive generator in the system. Nuclear power station (Koeberg) is a must run station and it is always dispatched to its maximum capacity available. The cycle efficiency of a pumped storage scheme (Drakensberg, Palmiet and Ingula), system costs (based on pumping requirements) and the historical generating patterns of existing schemes determine their generation pattern hence they are given minimum load factors. They are modelled such that their top reservoirs must be full at the beginning of every week.

Gariep and Vanderkloof generate as per agreement between Department of Water and Sanitisation and Generation Peaking department. The full capacity of these stations is thus not always available in all hours; they can only be dispatched for an agreed number of hours per day. The OCGTs are not fuel constrained but restricted by their availability, position in the merit order and also by the assumption on utilisation.

Coal fired power stations are modelled as per their technical parameters which include; number of units, units' end of plant life, minimum generation levels, ramp rates, energy cost, availability and other characteristics required by the tool. Dispatch of power stations will be based on their energy cost. Expensive stations are expected to produce less if the system is not constrained.

Non-Eskom generators (Imports and IPPs) are modelled as contracted to Eskom. Renewable IPPs are modelled using their hourly profiles for each technology to meet projected monthly/annual energy. Imports and IPPs are forced in the model to dispatch first and the remainder of the energy is met by Eskom generators.

3.13 The sequence of the process to determine the price adjustment is unclear

The consultation paper requires licensees to provide NERSA with information. (Please see the section on information requirement in this response). The format of the manner in which this information is provided is unknown and yet to be communicated to licensees. The information will be related to both financial and non-financial information for each level of activity defined by NERSA. The information will be related to Eskom and independent Power Producer (IPP) generators (at plant level), Transmission related information (please refer to concerns about level of information required in terms of the legislative compliance) and Distribution related information in the form of Distribution network and retail (concerns from a legislative compliance viewpoint).

In addition, NERSA has proposed that it will utilise further information that it will source from electricity customers to determine their usage patterns. This is not a requirement for licensees to provide to NERSA, since it will be independently sourced by NERSA. In depth analysis of this information will contribute to NERSA approvals on any price adjustments. Where direct information is not available (through smart meters), NERSA will apply benchmarks. The details of these benchmarks are yet to be communicated to electricity customers. It is indicated that NERSA will determine levels of affordability, profitability and competiveness to determine the prices. NERSA will then determine the prices for customers. It is unclear how customer groupings will be determined.

In accordance with the consultation paper, the methodology does not require a formal application of any sort. NERSA will utilise the information received from all licensees to make tariff decisions. It has been established that there is no direct traceable link between a revenue requirement and the final price adjustment decision. This indicates that the ability of the licensees to recover efficient costs and a fair return (in compliance with the ERA), is severely at risk.

It is understood that NERSA will use information sourced from licensees and customers to develop proposed tariffs. It is as yet not understood how these customer groupings, based on load profiles will be determined. It is likely that certain subjective criteria would be applied to arrive at these groupings. NERSA has referred to the application of benchmarks if information is not available. A key dependence seems to be on smart meters. These smart meters are yet to be installed. Details on the criteria and basis for benchmarking have not been included in this consultation paper. This would require further consultation at a later stage.

A majority of Eskom's business is regulated by NERSA. The Eskom Board's fiduciary responsibility requires it to ensure that Eskom is a viable business and can operate as a going concern. The recoverable revenue, for providing the regulated services, is a key element for the Eskom Board. In addition, the Shareholder, investors, credit rating agencies and lenders will only be able to undertake their roles and provide services to Eskom when the expected revenue for the entity is known. It is understood that a similar requirement is critical for other licensees such as municipalities. It is impossible to undertake any budgeting or planning exercise without knowing what the allowable/ anticipated revenue would be.

3.14 Insufficient detail on the permissible revenue determination for industry

NERSA proposal is as follows:

- *"The first set of rules deals with the transformation of costs (it is unclear whether these costs past costs or projected costs) into a permissible level of revenues. The calculation itself can be carried out whenever requested by a licensee or the Regulator or on a set time schedule. All of the customary elements of such calculations are included, such as a fair rate of return (based on the opportunity cost of capital), an asset base, depreciation, operating expenses, and taxes. (S 5.9.1)*
- *The basis for calculating permissible revenues must be clearly communicated to licensees (S 5.9.2)."*

It is understood that NERSA is still in the process of developing further details on how permissible revenue will be determined. If one were to compare the detailed requirement provided in the prevailing MYPD methodology, it is evident that NERSA is yet to provide further details that NERSA will consult on. This is a key area where what is permissible and what is not permissible will be elaborated. This is specifically pertinent since this methodology is now applicable collectively to all relevant licensees.

3.15 Transmission activities are not separated

It is clarified that the prevailing legislation does not require the separation of Transmission into Transmission services, Central Purchasing agency, System Operator and Market Operator.

The legislation requires a collective Transmission. In addition, it is understood that the IPP Office is an independent entity operating under the DMRE. The IPP office is not part of any licensed activity and is not regulated by NERSA. Thus, it is unclear how Eskom (where Transmission is presently licensed by NERSA) would have to provide information to NERSA related to the IPP Office. It has been highlighted that this is a policy decision that is yet been addressed by the DMRE. It should be noted that all aspects of Transmission have capital expenditure requirements.

3.16 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 (S4.6.2.2, footnote 8). 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 (S4.6.3.2) 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 (S 8.4.2.2)

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.

3.17 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. Thus "… *because if principles of merit order dispatch are observed, certain IPPs, especially from earlier bid windows will not necessarily be dispatched*" (S 4.3.4.3.1) is not understood in terms of power system dynamics and economics. The same applies to "*Expensive self-dispatching plants cannot trump another generator if merit order applied rigorously*" (S8.3.12.1). 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.

3.18 Unclear how Eskom generators will recover efficient costs for energy they provide

It has been clarified that this methodology will allow for Power Purchase Agreements with IPPs to be honoured. The process for this is not very clear. The consultation paper is not clear on how the permissible revenue will result in a generation tariff. It is unclear how various WAT will be determined. With regards to Eskom generators, they will only recover in accordance with the amount of energy provided. This is supposed to be an incentive for Eskom generators to provide more energy. It is unclear how capacity charges will be considered for Eskom generators – will the treatment be the same as for IPPs. However, on the flip side – if the generators are not available, they will not make themselves available for dispatch. How will this impact the security of supply? This is another fundamental risk that can have severe repercussions for the security of supply in an already constrained system.

3.19 Unclear how efficient Transmission and Distribution costs are recovered

The consultation paper does not clearly provide clarity on how the proposed permissible revenue is firstly determined and then a tariff is determined thereafter for both Transmission related services and Distribution services.

3.20 Unclear on how revenue requirement for coal costs are recovered

No details are provided on the determination of revenue related to coal costs. Reference is made to *"Costs will be allowed based on acceptable industry standards or benchmarks. Transparent benchmarks are a conventional and recognised regulatory alternative to addressing information asymmetry."* (S11.3.2) (Appendix C). However, no details are provided on what this entails. This is an enormous risk that originally led to the development of the detailed process for the recovery of efficient coal costs.

3.21 Unclear on how regulatory asset base is valued

NERSA refers to a *"preference"* for the valuation of the regulatory asset base (RAB) being on a historical basis. (S5.14.1.2). However, depreciation is based on replacement valuation (S 5.14.5.1). There seems to be some contradiction. However, be that as it may, the EPP clearly requires the valuation of RAB at replacement value.

The process to determine the RAB by licensees is not stipulated in the consultation paper on the methodology. A further consultation on this requirement is anticipated before the finalisation of the methodology. This is especially the case since this consultation paper addresses all licensees on a level playing field. It would be pertinent to ensure that all licensees will be provided with requirements on the valuation of the RAB. Roles will likely be defined for licensees as well as for NERSA before the RAB is finalised.

3.22 Unclear how depreciation will be determined

"The economic life for the regulated Generation, Transmission and Distribution assets shall be determined by the licensees and approved by the Regulator." (S 5.14.5.2). It is unclear when and part of which process this will be done. It is recommended that the correctness of the formula referred to be clarified.

3.23 Ancillary Services costs

It is agreed that it would be best to ring-fence ancillary services (AS) costs within Transmission. In certain clauses of the consultation paper, ancillary services costs are a subset of System Operator costs (S1.3.9). However, in other sections of the consultation paper, AS costs are separate from system operator costs. It needs to be noted that the EPP requires the ancillary services charge to recover the system operator costs including the ancillary services costs. The concepts of AS costs and charges seem to be mixed up and creates confusion. This would need to be clarified in subsequent consultations.

3.24 Consideration of stranded assets and decommissioning provisions

It is acknowledged that the electricity infrastructure development and operation is very complex and spanning over many decades. To contribute to security of supply, certain investments need to be made that are guided by legislation. Recovery of efficient costs for what may be deemed to be stranded assets needs to be considered. In addition, significant decommissioning provisions need to be made. The costs associated with such activities are legitimate costs for the efficient operation of the industry. It is unclear how these are considered in this consultation paper, if at all.

3.25 Unclear on how migration to cost reflectivity is continued

NERSA is aware that as far as Eskom's allowable revenue is concerned, a migration towards cost reflectivity is still a journey being undertaken for many years. The key element of allowable revenue that was used to facilitate this journey has been the return on assets (ROA). In the recent past, NERSA has allowed negative ROA from FY 2020 to 2022. The ROA for FY 2023 was determined at approximately 1%. For FY 2023 NERSA has determined the weighted average cost of capital (WACC) to be 9.87%. The difference for the ROA revenue element, if determined at the WACC would be approximately R62bn (for an average RAB value of approximately R700bn). This difference alone, would correspond to approximately a further 25% increase based on a total allowable revenue of R250bn.

In this consultation paper, NERSA has indicated that ROA will be determined at WACC. It is possible that could result in a tremendous increase in prices for all customers, since such a radical change is being proposed. The means for migration to cost reflectivity has now been removed.

3.26 How would NERSA meet its Court ordered and RCA commitments

NERSA is required to meet its court orders related to implementation of revenue recovery and price adjustments. Included in these commitments are:

3.26.1 Supreme Court of Appeal order, dated 6 June 2022 (case number 953/2020)

"After such time as NERSA has determined the allowable revenue for the 2023/24, 2024/25, 2025/26 and 2026/27 financial years, the following sums will be added to those determinations:

- *In FY 2023/24, R15bn will be added to allowable revenue;*
- *In FY 2024/25, R15bn will be added to allowable revenue;*
- *In FY 2025/26, R15bn will be added to allowable revenue;*
- *In FY 2026/27, R14bn will be added to allowable revenue."*

3.26.2 High Court order, dated 6 July 2022 (case number 51550/2021)

"Eskom's revenue application for the 2023/24 financial year, submitted to NERSA on 2 June 2021, is to be decided by NERSA in accordance with the 2016 Multi Year Price Determination Methodology ("the existing Methodology", on a timetable to be determined by NERSA subject to the following:

- *NERSA shall publish the 2023/24 revenue application on or before 1 August 2022.*
- *NERSA shall provide a period for the public to make written representations in response to the 2023/24 revenue application.*
- *After the deadline for written representations in response to the 2023/24 revenue application, NERSA shall convene public hearings on the 2023/24 revenue application.*
- *NERSA shall make a final decision on 2023/24 revenue application on or before 24 December 2022.*

The revenue application for 2024/25 shall be determined in terms of the Methodology which will be in existence at the time. This could include a methodology based on the amended Electricity Regulation Act and Electricity Pricing Policy or a methodology determined by NERSA after having completed the revision of the existing Methodology having regard to any other regulatory requirements for the industry.

If NERSA publishes a new Price Determination Methodology and reviews all other related regulatory requirements for the industry by 30 September 2022, Eskom shall submit a revised 2024/25 revenue application by no later than 1 June 2023 to NERSA for consideration and approval by 20 December 2023."

3.26.3 Various court matters still underway impacting revenue and price adjustments

These court matters include:

- Review of NERSA decision on Eskom's RCA application for FY 2018
- Review of NERSA decision on remitted RCA for FY 2015 to 2017
- Review of NERSA decision on remitted Eskom FY 2019 revenue decision and review of Eskom FY 2019 RCA application
- Review of Eskom FY 2023 revenue decision
- Review of NERSA FY 2021 decision to adopt a methodology for the determination of municipal electricity tariffs by the "guideline and benchmarking method".

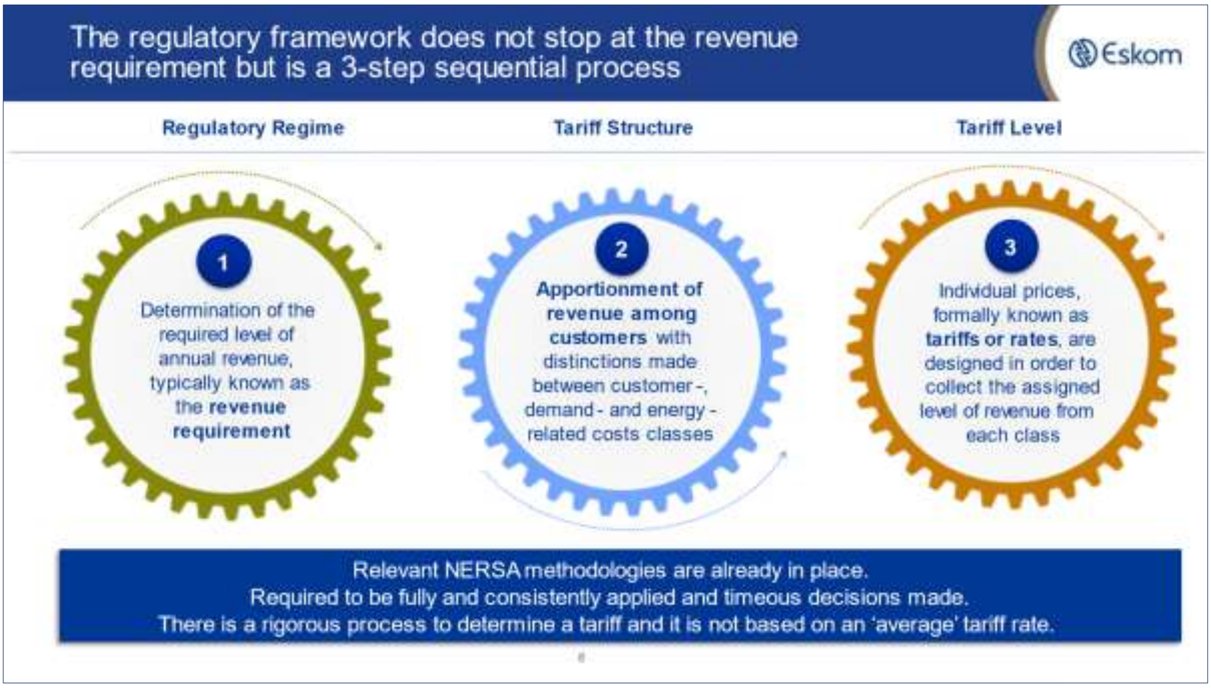
It needs to be noted that both the SCA and High Court order that NERSA will need to uphold requires the determination of allowable revenue at an Eskom level. However, the allowable revenue at an Eskom level is no longer determined by NERSA, if the proposed methodology is implemented. This is likely to create a challenge to NERSA in meeting the requirements of the court orders. The consultation paper has also failed to acknowledge these commitments and provide ways of how they will be dealt with under the proposed methodology.

4 Determination of Tariffs

4.1 Globally recognised methodology presently in place

Presently, the following process is followed. These details were shared during the NERSA consultation on principles to determine a price determination methodology during 2021.

Figure 3: Three step process to determine tariffs



The above three step process is followed by Eskom, together with NERSA to determine tariffs. The first step is the determination of allowable revenue, through the implementation of NERSA's MYPD methodology. Eskom has to provide the necessary detailed information by the submission of minimum information for tariff applications (MIRTA) templates. The second step requires the apportionment of revenue among customers in accordance with NERSA cost to serve framework. NERSA then approves tariffs in accordance with the NERSA Eskom retail tariff and structural adjustment (ERTSA) methodology.

While it is true that averaging is applied in the determination of Allowed Revenue – it is crucially important to recognise that the 'pricing approach' does not end there.

At the risk of over-simplification [1]– the MYPD Methodology requires that the costs of Generation and Transmission are to be passed through to Distribution and recovered in the form of retail charges and tariffs. It is here that the principles of cost reflectivity and causation at the level of the end user come into far greater focus.

4.1.1 Transmission charges

The Transmission Tariff Code (Version 10) as approved by NERSA provides for the recovery of approved costs associated with owning, maintaining and operating a transmission system (TS) by way of transmission tariffs. Following principles of cost disaggregation, allowable costs to be recovered from TS users are comprised of:

- Network charges
- Losses charges
- Reliability services charges
- Connection charges

Network charges and losses charges are recovered from transmission customers on the basis of Notified Maximum Demand (KVA). Reliability charges are recovered on the basis of energy usage scaled to just recover ancillary services costs. The connection charge is based on the cost of assets used for the benefit of the connecting customer.

4.1.2 Distribution Tariffs

In a broadly similar manner, the Distribution Code sets out objectives and principles for pricing and tariff structures for energy, distribution network and retail services. There are well over forty stated objectives and principles provided in the Code. For the sake of brevity we highlight Section 7(1) that speaks to the use of cost drivers in the design of cost reflective tariff structures and the mitigation of risks by way of under and over recovery mechanisms.

"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,

[1] The treatment of Special Pricing Agreements and imports and exports is not incorporated in this simplified view as is not viewed as material to the point being made.

through appropriate tariff or claw-back mechanisms (for both under or over recovery of revenue) within the revenue requirement.

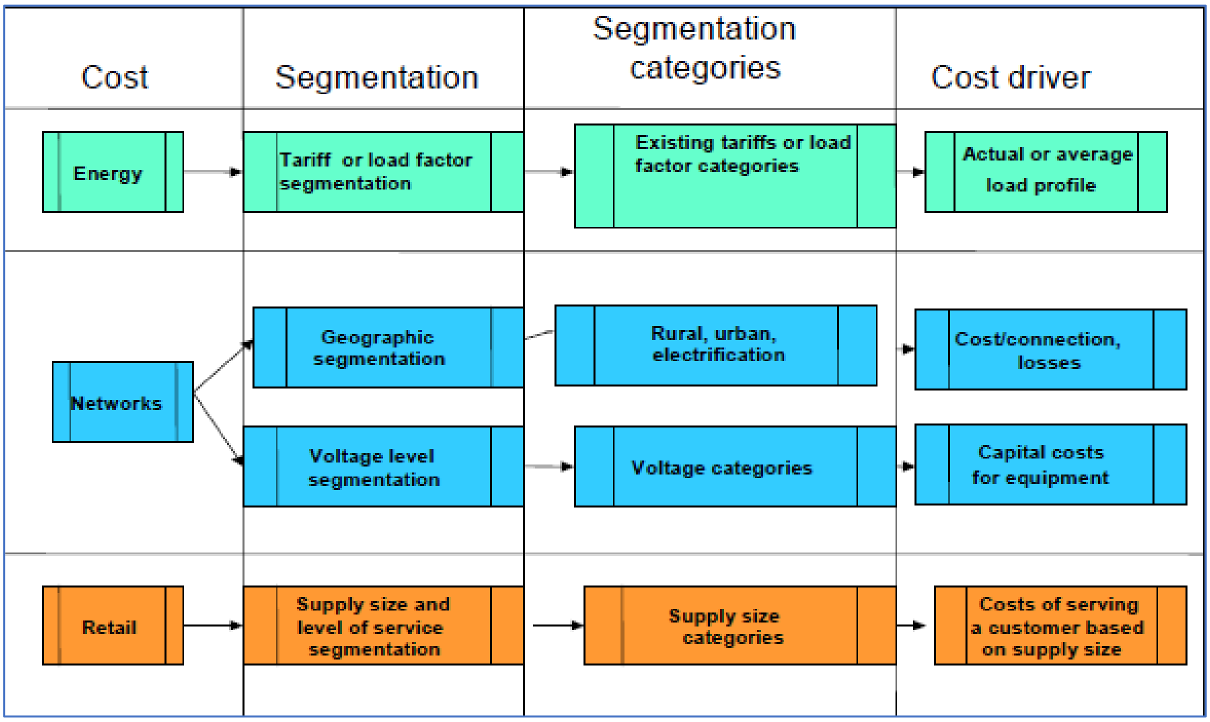
With Section 7(5) speaking to tariff complexity and the need for a level of aggregation.

"The tariff structure ultimately used will depend on customer needs, meter capability, billing functionality and logistics, and limitations on tariff complexity. This will cause aggregation of various cost components and cost drivers in the tariff applied.

And that

",,, electricity supply costs must be unbundled into Energy purchases; Network costs (transmission purchases distribution costs) and Retail / service components."

The process as illustrated in Distribution Code is shown below.



Source: Distribution Tariff Code, Diagram 2

- Costs are disaggregated at the level of licensed activities.
- Costs are segmented by services provided and customer characteristics.
- Causality based cost drivers are identified that align to segmented costs.

It needs to be emphasised that methodologies such are the MYPD methodology is not defective. It is the application of these methodologies in the recent past that has resulted in poor outcomes. It is unfortunate that reviewable decisions continue to be made. Significant progress could have been made if the methodologies were correctly implemented. In a similar manner, it would be advantageous to implement the proposed retail tariff plan to be submitted to NERSA during August 2022.

4.2 Eskom's Retail Tariff Plan

In addition to the existing processes, the retail tariff plan (RTP) makes proposals that meets the key objectives that NERSA is trying to meet. This is done within a legitimate legislative framework and in an implementable fashion.

In 2020, Eskom submitted a tariff restructure proposal to NERSA that offers a first step to unpacking the value-chain activities to reflect related NERSA allowed costs to the end-customers; Eskom will again submit the proposals in August 2022. The attainment of key objectives supported by the EPP in the Eskom tariff restructure are highlighted accordingly to supplement the discussion of the proposed methodology.

In addition to the sound principles contained in the Distribution Tariff Code, the provisions of the EPP informing tariff setting and structures of retail tariffs is summarised in the table below.

Table 2: EPP informing tariff setting and structures of retail tariffs

Retail tariff charges (EPP)	NERSA proposal	Eskom retail plan
Cost of supply studies The basis for tariff restructure proposals to the Energy regulator.	• Tariff unbundling proposed but omits mention of retail (trader) cost of supply studies • Disregards the NERSA cost of supply framework.	• Compliant with the EPP • Last submitted Cost of supply study provided to NERSA in 2020 and the proposed plan based on a cost to supply study.
Cost reflectivity Pricing method to reflect the full economic cost of supplying electricity to a customer	• Aligned to the EPP statement but distorted when customer load types are considered given the link to the generators supplying is not proven and would lead to non-cost reflective energy pricing.	• Compliant with the EPP based on a NERSA approved revenue and requirements to develop cost reflect tariff structures; this is reflected in the proposed retail tariff plan.
Customer categories 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)	• Not compliant with the EPP • Limits the development of customer categories to 4 load type groups based on load profiles and not clear of the time periods and if referring to load factors. and summarises this into 4 categories irrespective of their usage times, load factor and average consumption, type of supply/connection equipment, density of location, metering, voltage of supply	• Compliant with the EPP for all cost differentiation factor and this continues in the proposed retail tariff plan.
Distribution network tariffs • To reflect the cost of using the network by differentiating charges based on voltage of supply in the distribution network. • Overtime to reduce the phased increases to tariffs at	• Not compliant with the EPP • Single R/kVA charge (no voltage differentiation) distorting the cost of using the network for wheeling and retail end-customers whilst increasing tariff cross-subsidies.	• Compliant with the EPP. • In the proposed plan, implements the EPP requirement to increases to tariffs at lower voltages and increases to those at higher voltages.

Retail tariff charges (EPP)	NERSA proposal	Eskom retail plan
lower voltages and increases to those at higher voltages.		
Distribution losses and Bad debt • NERSA to provide a standard to Distribution losses and bad debt	• Not compliant with the EPP • Methodology does not provide for Distribution losses nor the related standard	• Compliant with the EPP. • Proposed plan uses the NERSA approved costs for Distribution losses and bad debt as contained in the allowable revenues
Distribution network tariffs • To reflect the cost of using the network by differentiating charges based on voltage of supply in the distribution network. • Overtime to reduce the phased increases to tariffs at lower voltages and increases to those at higher voltages.	• Not compliant with the EPP • Single R/kVA charge (no voltage differentiation) distorting the cost of using the network for wheeling and retail end-customers whilst increasing tariff cross-subsidies.	• Compliant with the EPP.
Energy charges • Time-of-use (ToU) for Wholesale and retail tariffs; Aligns generation, transmission, distribution and consumption costs and mitigates risk of cost recovery and customer under/over payment • Where metering / customer understanding dictates flat rate charges based on ToU costs.	• Not compliant with the EPP • Flat rate load type category and single tariff depending on load type.	• Compliant with the EPP. • Proposed plan reduces the difference between winter peak and summer off-peak from 1:8 to 1:6, a 25% decrease.
Flexibility to package electricity for sale • Allows special products and prices to achieve specific goals, the cost of which will be treated to the regulatory methodology	• Not compliant with the EPP • Limits the tariffs to the provided options.	• Eskom proposals for different tariffs provided including the price signals contained in the energy ToU tariffs.
Price path • NERSA after consulting with stakeholders, to develop and publish a multi-year price path on an annual basis.	• Not compliant with the EPP • Methodology mentions an update every 5-years and included are quarterly retroactive adjustments after 12 months. This indicates increase unpredictability for energy purchases. • The Methodology does not provide the approach for the multi-year price path.	• n/a
Transmission charges • Separate Wholesale costs for Transmission networks, ancillary and transmission losses reflecting distance differentials.	• Not compliant with the EPP • Combined Transmission and ancillary services charge. • Limits customer view of ancillary costs used to supply. • Lacks the required geographic differentials updated and approved considering	• Compliant with the EPP. • Transmission loss factors updated in proposed plan to more accurately reflect the cost of transmission network losses and network charges along the existing geographic differentials.

Retail tariff charges (EPP)	NERSA proposal	Eskom retail plan
• Transmission geographically differentiated tariffs informed by a redefinition developed by the DMRE and NERSA after considering price stability and comparing the current generation mix to the foreseen in the next 10 years.	generation mix and the long-term.	
Voltage differentiated network tariffs • Voltage and supply position differentials must be applied in tariffs 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. • NERSA must create a plan for phased increases to tariffs at lower voltages and increases to those at higher voltages.	• Not compliant with the EPP • Methodology disregards voltage differential and consolidates the demand and energy related costs.	• Compliant with the EPP. • In the proposed plan, implements the EPP requirement to increases to tariffs at lower voltages and increases to those at higher voltages.

4.3 Challenges related to proposal on "Type of Use" tariffs

In South Africa, we still have a regulated mostly vertically integrated system, with some bilateral trade and intend to move to an energy market over time. We therefore do not have marginal market-based pricing but use time-of-use (TOU) tariffs as a proxy for marginal costs and to provide pricing signals to customers to assist the system operator with higher prices in peak periods and lower prices in off-peak and standard periods. This also provides incentives to customers to save if they shift load.

At this stage Eskom develops tariffs based on wholesale energy prices that are TOU and this is then passed onto end-use customers based on the wholesale TOU rates plus losses. NERSA wanting to move away from TOU to the type of use approach is a major deviation of the current approach, is not cost-reflective, does not consider how wholesale pricing works and appears to benefit on one sector at the cost to other sectors.

NERSA's argument is that baseload (those with a flat profile) customers like smelters do not have the ability to shift load and therefore TOU tariffs serve no purpose and creates inefficiencies in their production. However, this is not true as there are examples of energy intensive customer users that do respond to pricing signals by shifting most energy-intensive activity into low-cost hours in response to time-varying rates. Eskom also notes that in particular, response to times and seasons, plants are taken out for maintenance as a response to TOU. Another is that the baseload plants are often largely depreciated coal plants, coming it at the cheapest cost, which implies these baseload customers will be allocated the cheapest energy.

This 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.

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," 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.

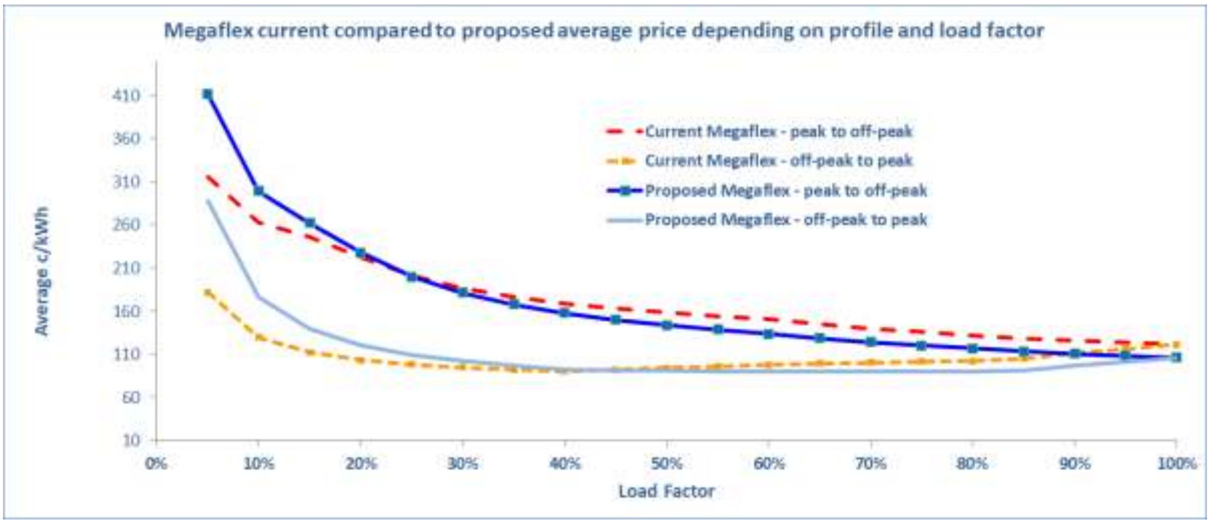
It is Eskom's stance that all costs of all generation needs to be allocated to all customers in the hours in which they are providing power (sum of all; baseload to all hours + solar to daytime hours + wind to whatever hours it blows+ peaking plant to peak hours, etc), and then assign those costs to classes, and ultimately to tariffs and customers on the way they use power in those hours – not based on whether they are a baseload customer or not.

Even if some customers have a steady flat demand and others have a specific peak period demand, the causal responsibility for peak capacity rests on all types of customers consuming in a peak hour.

However, TOU tariffs already provide the lowest prices for high load factor customers, as the TOU rates are spread across all time periods, including the cheapest off-peak periods. Therefore, under TOU tariffs higher load factor consumers are still very likely to have lower overall average costs/kWh so these customers are still getting a benefit, but then have the motivation to move high costs kWh to low-cost kWh.

This is shown in the graph below which indicates the average price at different load factors paid at the current Megaflex tariff compared to the revised Megaflex that will be include in Eskom's Retail Tariff Plan. The introduction of the generation capacity charge further supports high load factor customers (flattens the TOU impact)

Figure 4: Megaflex current compared to proposed avg price depending on profile and load factor



It is, therefore, not clear what the rate design objective is for this proposal by NERSA, but it's not something that makes sense for residential customers, or even municipalities as they have the peakiest profile and therefore would be allocated the most expensive generation plant costs, or how this proposal would benefit system and grid efficiency improvement. A flat rate based on someone's load factor is still a flat rate, and there's no signal for anyone to shift behaviour. Without TOU tariffs, customers would have no incentive to reduce load in high-cost peak periods and this would certainly create significant risk for the Eskom system, as customers do and are responding to the TOU signal. The Eskom System Operator uses customer response to TOU tariffs.

The NERSA proposal is also not aligned with the economics of running a power system. A power system is managed by allocating the least marginal cost generation first (which is Eskom's case is renewables and nuclear) and then further dispatched on price to meet the system demand. The marginal price paid to the generators is then based on the last generator dispatched to balance supply and demand. Under a market, even a base-load customer buying in the market would be exposed to the price set for that hour and not for example the price of the lowest cost generator.

This proposal further significantly complicates how retail tariffs are to be designed and introduces greater cost recovery risk at the retail level. Eskom Distribution and municipal licensees will be exposed to significant cost-recovery risk. At the retail level (that is the price paid by the end-use customer), energy is purchased at a wholesale energy prices. The wholesale price is determined taking into account the regulated allowed revenue (costs plus return) of Eskom generation and Eskom's IPP purchases that is then purchased by the wholesaler, through an internal transfer mechanism. This price paid is based on tariffs raised by each Eskom generator based on the marginal costs as dispatched and the PPA terms with the private IPPs. The wholesale energy costs are then converted into a TOU based energy and now a capacity charge and through an internal transfer price is raised to Eskom Distribution as the retailer to pass this though in the retail tariffs to end use customers. Added to the wholesale price paid by Eskom Distribution, are Transmission charges, Distribution charges and retail charges to get to the retail tariffs (unbundled as far as possible).

At the retail level there is currently no direct link with generators or generator purchases as this is all done through the Wholesaler whose function resides in Eskom Transmission. The NERSA approach seems to indicate that the wholesale tariff needs to be split up into 4 tariffs depending on load profile and not TOU and then we need to somehow pass this onto customers in the retail tariffs depending on their load type. This would require increased complexity and forecasting that would be needed to be given to the wholesaler in order to determine different wholesale rates and this would somehow have to be passed in the retail tariffs to customers.

The NERSA proposal also ignores how Eskom would raise such complexity in the tariffs to municipal licensees, which have many points of supply with differing load profiles. As a last point, there is concern about the generality of the "load types" and as they are proposed does not make logical sense as no customer on average would fit into any of the load types. Also to be noted, that any baseload customer that decides to wheel power or install own generation, could no longer be considered as load type 1.

Type of use ignores that usage is not only dependent on supply but also other factors like commodity prices, country risk, etc. and this will impact the load profile types on a more volatile basis than NERSA assumes.

There are too many questions on the implementability of the proposed "Type of use" and the WAT formula, for example:

- What happens if load profile changes in a month – but forecast year ahead? How will cost recovery be dealt with in tariffs if forecasts change?
- Who will approve the forecast?
- How will munics be able to cater for the different load types?

5 Information and Resource Requirements

5.1 NERSA yet to update methodology with required licensee information requirements – which needs to be consulted on

In dealing with the unbundling of costs under section 6, reference is made to Annexure E as the "format in which this information is required" for licensees. However, within Section 6 in the consultation paper reference is made to "intense" data requirements" and in this regard reference is also made to "developed templates", "workbooks" and "data collection tool' to assist licensees to comply with data requirements. However, these "developed templates" and "workbooks" have not been shared as part of the consultation paper to enable the licensees to assess the level of detail requested, the availability of data requested and if such data is not readily available; the processes, systems and timing thereof to enable the licensee to make such information available to ensure compliance. Complete data requirements (templates, workbooks, etc) should form part of this consultation process in order for stakeholders to meaningfully "comment on the data intensiveness and propose solutions on how licensees can be assistance to be compliant".

Annexure E also makes specific reference to "two generation workbooks (one Eskom specific and one for use with any generator), as well as to "a workbook has been designed for the collection of data about what is referred to as 'distribution wires' activities". As mentioned above these need to form part of the consultation paper to enable stakeholders to comment on the data requirements.

In addition to the above, the proposed timeframe is also not clearly defined. "Data needs to be submitted once every five years (or longer) and will be reviewed on a yearly basis". What alternative timeframe is being proposed? It is also not clear what the yearly review will entail i.e. the level of data being reviewed, what further information will be required to be furnished and in what format, and what are the timeframes for this process? The timeframes and data requirements for this process are not clearly defined.

In addition, no firm proposal is made in terms of the timeframe required for prior year/actual data requirements, or the MYPD period itself. NERSA merely dispels the current MYPD "maximum five years" period in terms of current practice but fails to clearly define the new MYPD period. In stating "individual tariffs can be set for the expected life of the asset", NERSA has left the timeframe open ended. The timeframe of forecast data should speak to the accuracy and integrity of available data given current economic, socio and political conditions/uncertainty in setting cost reflective tariffs to enable any entity to be financially sustainable.

It needs to be acknowledged that licensees will require time and resources to enable information to be provided. Once NERSA has consulted on the details in the workbooks, templates, etc – licensees will need to be given time to ascertain whether information is available in the format required. The timing and resource requirements could then be factored into any information requirement process.

NERSA has acknowledged, during its consultation workshop on 20 July 2022 that it has not been successful in securing required information from many Municipalities. It is understood that this information is required by NERSA, from Municipalities, in terms of their licence conditions. It was indicated that cost to supply studies have not been provided by many Municipalities. However, this consultation paper indicates the dependence on information from all licensees. It is unclear how licensees will be treated equally if the dependent information is not provided. Significant assumptions would need to be made. Is it possible that certain customers may feel aggrieved and thus review decisions that NERSA makes?

5.2 Consumer data to be sourced directly by NERSA

Section 7 in the consultation paper refers to "significant amounts of data" to be provided to NERSA. No detail and clarity is given as to who must provide what data and in what format. NERSA needs to give clear direction within a formalised process. The NERSA mandate with regards to sourcing of information from customers is unclear. In addition, NERSA stipulates that "comprehensive data collection" will be essential with NERSA starting with energy demand side surveys to source data from traders. Formal data reporting templates will be developed as part of the implementation of the methodology. When will these templates be developed and shared? Should these templates and surveys methods not be part of the consultation process to ensure transparency? No timeframes are proposed within these data collection processes.

Where data is unavailable the concept of benchmark profile has been suggested. The process and data used for benchmarking has to be transparent and within any regulatory framework. Need to assess risks and data integrity of information being used and if this is a fair process. It is necessary to consult with licensees on this benchmark profiling process.

a. Permissible revenue

Some indication of the kind of information required has been provided. The detail of this requirement is addressed elsewhere in this response submission. However, the details of information required in the form of workbooks and templates is crucial. On the assumption that NERSA (ERA, NERA) and licensees (such as GSFA, MFMA) can meet their legislative requirements, it needs to noted that since the entire price adjustment and tariff process will be centralised within NERSA, clear and precise direction is required for licensees to be in compliance with this requirement. Details are yet to be communicated and be consulted on. Once this information is communicated, consulted on and finalised, licensees will require resources to implement these requirements to be enabled to provide the requisite information. These resources include financial resources, supporting systems and processes, skills and time.

b. Rules for setting rates and tariffs

Some indication has been provided on the approach to be followed. Has been discussed in other parts of this response documents. However, the details of information required in the form of workbooks and templates is crucial. It needs to be noted that since the entire price adjustment and tariff process will be centralised within NERSA, clear and precise direction is required for licensees to be in compliance with this requirement. Details are yet to communicated and be consulted on. Once this information is communicated, consulted on and finalised, licensees will require resources to implement these requirements to be enabled to provide the requisite information. These resources include financial resources, supporting systems and processes, skills and time.

c. Rules for altering tariffs

Indications have been provided that monthly/ quarterly adjustments will be made. No details on what Step 3 entails has been provided. It is not clear how this will be done. No details on the kind of information required have yet been communicated in this consultation paper. Thus, it is envisaged that further consultation on this matter would be undertaken by NERSA, once these requirements have been developed by NERSA.

5.3 Unclear on how monthly and quarterly reviews are undertaken

Indications have been provided on monthly or quarterly reviews being undertaken. However, not much detail is provided on the processes to be followed and the information requirement for such adjustments. The implementation of outcomes of reviews have not been communicated.

It is also unclear how quarterly changes in prices will be implementable. It is unclear how the requirements of the Municipal Finance Management Act (MFMA) will be complied with. This also imposes challenges on the Minister of Public Enterprises, who will be put in an impossible position. This in turn would have implications on the viability of the licensees who may not be able to implement the proposed quarterly price adjustments.

5.4 Smart meters

It seems that the smart meters will be extremely ingenious. They will be able to determine the load profiles – whether baseload, mid-merit, peaking or emergency. There is an implication that customers are responsible to provide smart meters and for customers to provide this data to NERSA. If customers cannot provide meters, then benchmark profiles will be used for them. NERSA depends on roles of smart meters as being critical and essential to monitor and allocate various load profiles. The costs associated with replacing all meters with smart meters would need to be considered from a cost-benefit point of view. A conservative estimate of replacement all approximately Eskom's 7million customers with smart meters amount to approximately R15bn. The timing and resources for such a situation needs to be considered from a cost benefit analysis.

5.5 Ability for billing systems to deal with proposed methodology

Without a true understanding, in particular, how the different load type could be implemented and what the eventual tariffs would look like, there may be complexities that cannot be accommodated in the Eskom billing system or municipal billing systems. No assessment of this impact was considered or consulted on in this consultation paper.

6 Potential for increased risks

6.1 Increase in risk to the electricity industry

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 is now positioned within NERSA. Licensees are required to provide information to NERSA. No applications for revenue or price adjustments will be made. 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.
- **Radical big bang change is proposed**. The viability of such an approach is questionable. It seems to be a radical change from the present process 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
- **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 in the legislation.
- **Non-compliance with existing legislation** There are numerous areas of the consultation paper that seem to be 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. 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. 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 seem to be 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 seem to be 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 for a crucial aspect that affects 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 and ability of licensees to be able to respond appropriately.
- **Seems to be designed for a particular group of customers.** Indications are that this entire review process is being undertaken to meet the apparent requirements of what are considered to be "baseload industrial customers".
- **This is an untested methodology.** It has not been possible to establish where in the world this "type of use" 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.
- **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.

- **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. 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. A proposal is for all generators to be treated in the manner that the REIPP projects are addressed. It is unclear exactly how this will work. 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. 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.

- **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 of information.
- **Dependence on smart meters and supporting 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
- **Dependence on fiscus is referred to.** The price of electricity is already being subsidised by the taxpayer. There seems to be further uncertain amounts of subsidy being proposed. 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.
- **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 residential customers will be significantly impacted by price increase.
- **Discrimination could be inferred.** The possibility of certain customer groupings being seen to be discriminated against may be a risk. This will likely be seen as non-compliance to the ERA – with relation to non-discrimination.

7 Recommendations and way forward

7.1 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 deliver on the requirements of this methodology
- 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

7.2 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.

7.3 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 a 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.

1. 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.

2. 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.

3. 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:

1. **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.

2. **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.

3. **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.

1. 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.

2. The objective of the retail tariff plan is to reflect costs more accurately by:
   a. Avoid unjustified over/under-recovery of costs from customers and creating unintended subsidies.
   b. Ensure fairness and equity and transparency of subsidies existing in the system.
   c. 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."

3. 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.

4. The type-of-use 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.

7.4 Eskom's RTP implements key objectives

Eskom last revised its tariff structures in 2012 and is proposing structural changes to the Eskom tariffs, based on an updated cost-of-supply (or cost-to-serve/CTS) study.

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, submitted proposed structural changes to NERSA based on the principles in the EPP and NERSA previous decisions. This submission is 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.

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:

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

a) 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.

b) 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).

[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.

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 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.

c) 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.

d) 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.

2. 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.

3. 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.

4. **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.

5. **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.

6. **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.

7. **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.

8. **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).

9. 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.

7.5 Conclusion

Arising out of the challenges and risks identified, it is proposed that all stakeholders be encouraged to continue to participate in NERSA consultation processes through various iterations to further develop the methodology. It is also recommended that NERSA make an assessment whether it wishes to await the amendments to the ERA and EPP prior to finalising the methodology. Whatever approach is adopted will still allow for much more work to be done on developing an implementable methodology. It is urged for NERSA to genuinely engage on comments and responses provided to allow for robust engagement for the enrichment of the methodology. It is essential to ensure that the proposed methodology is compliant with prevailing legislation and Government policies. It is essential for the methodology to be implementable. This may require a revisit on how the objectives can be met. It is evident that this approach is dependent on vast amount of information. The iterative process will accommodate a sharpening on the focus of information that is available and processes that need to be undertaken to source the information. This will all contribute towards the implementation of the methodology, when the time arrives. The time will also provide for any reviews of related methodologies, codes and guidelines – as may be required. Other policy issues, such as subsidies will require engagement with relevant Government authorities.

A cost of serve methodology has been the basis of regulating utilities (not only electricity) for decades. It is a globally accepted methodology that has stood the test of time. It is submitted that such a methodology can never be outdated. Our experience in South Africa, has not been due to challenges with the methodology, but the manner in which NERSA has applied the methodology. A summary of regulatory models being all based on a cost of serve methodology has been illustrated to provide a context to NERSA as it finalises this methodology.

In the interim while awaiting finalisation of methodology, it is proposed that the country continue to employ prevailing methodologies to migrate towards cost reflectivity at revenue and tariff level. It is critical to implement Eskom's Retail Tariff Plan in FY 2024 to allow for further unbundling and cost reflectivity at tariff level.

8 Responses to Stakeholder Questions

Stakeholder Questions - Main Document

From the information contained in the document, it is not clearly understood how the responses obtained from the myriad of questions posed will be translated into clear and concise rules and regulations that will serve as the basis for a methodology governing the electricity industry, whose transition towards a competitive electricity market is still underway and whose end state is not as yet known.

It can thus be inferred, from the inputs being sought, that there is still a significant amount of work that would still need to be undertaken by NERSA to translate the contents into a workable and implementable methodology that can properly guide licensees in making revenue applications.

In addition, presently NERSA can only work within the prescripts of the existing legislative and policy framework – i.e. the existing ERA, existing EPP, and Licensee Codes etc. We are aware that both of these documents are currently being reviewed and will be finalized soon. Once enacted, NERSA would be in a position to develop the necessary rules, regulations and codes that give effect to any changes enacted with regards to the electricity industry – i.e. "cannot put the cart before the horse".

NERSA methodology is subordinate to the requirements of legislation – i.e. the ERA and EPP and thus the rules developed by NERSA must be aligned to the policy objectives of both the ERA and EPP, both of which are currently being revised. It will thus be prudent for NERSA to await the finalisation of these policy frameworks before finalisation so as to ensure its methodology addresses the intended objectives. It will also result in more focused feedback being sought from stakeholders and more meaningful engagements can take place.

By following the correct hierarchy of events, NERSA will also be better guided to engage and consult stakeholders on an agreed upon / set outcome that is being proposed for the electricity industry as opposed to seeking responses to questions that proposes a myriad of options for the restructuring of the electricity industry and has the makings of a 'fact finding' exercise.

8.1 Stakeholder Question 1

a) The methodology seeks to uncover all licensees' costs within the ESI, including municipalities. Stakeholders are requested to comment on the move from an approach based on approving municipal tariffs to one that sets municipal tariffs based on unbundled costs as proposed by the methodology.

Eskom's Response:

The review of the Electricity Regulation Act (ERA) and the Electricity Pricing Policy (EPP) is currently underway. Both these legislative frameworks aim to pave the way forward for the reform / restructuring of the electricity industry. Any changes to the Distribution sector (including Municipalities) will be informed by the said policies.

We are not in a position to comment on municipal processes.

8.2 Stakeholder Question 2

a) Stakeholders are requested to comment on the profit determination mechanism as proposed by NERSA under 6.13.7. Stakeholders are also requested to provide alternative mechanism and motivate for the proposed approach. *b) Historical cost basis is NERSA's preferred approach for asset evaluation method when determining RAB. What is the view of stakeholders on this preferred approach and provide the motivation for preferred approach?*

Eskom's Response:

a) Profit determination mechanisms

There is no section 6.13.7 in the document. We assume NERSA is making reference to the section 5.14.7 which deals with profit sharing mechanisms.

The ERA and EPP are currently under review and it is envisaged that these will pave the way forward on the proposed market structure as well as the proposed profit sharing mechanisms for all stakeholders in the electricity industry.

b) Determination of the RAB

The prevailing legislative framework must be adhered to. The requirements as set out in the current EPP (2008) in so far as the asset valuation methodology is as follows:

Policy Position: 1
*a) 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. <u>The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that</u> **<u>accurately reflects the replacement value of those assets</u>** <u>such as to allow the electricity utility to obtain reasonably priced funding for investment; to meet Government defined economic growth.</u>*

b) In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator,

Hence replacement value and not historic cost as alluded to by NERSA in this consultation must be used to determine the RAB in line with the existing legislation.

In order to ensure fair and equitable treatment of all Licensees, it is proposed that the asset valuation methodology should be standardised, and it should accurately reflect the replacement value of the assets.

8.3 Stakeholder Question 3

a) Stakeholder are requested to comment of data intensiveness and propose solutions on how licensees can be assistance to be complaint.

b) Stakeholders are requested to comment on the proposed timeframe for licensees to submit their information.

Eskom's Response:

a) Stakeholder are requested to comment of data intensiveness and propose solutions on how licensees can be assistance to be complaint.

There seems to be mounds of information (albeit not clearly spelt out) being sought at various levels of the electricity industry value chain from both licensees and consumers.

In the absence of the workbooks and details on what exactly is required, a meaningful investigation of the viability and availability of the information being sought cannot be undertaken. NERSA to provide data collection tool and format.

It is envisaged that once NERSA has developed the specifics (including said workbooks etc.) of what is required, stakeholders will be engaged and consulted so a detailed analysis can be done to assess what would be feasible, including an assessment of the impact on current processes and systems. In addition, there would need to be a clear understanding and agreement on the application of Activity Based Costing (ABC) as our understanding ABC vs NERSA's interpretation seems to be different.

It is therefore also envisaged that once the methodology is in place, licensees would be afforded an opportunity to develop an implementation plan to pave the way forward to ensure compliance is met. This would be a gradual process and it cannot be expected to be a big bang approach as many changes would need to be made to give effect to any changes in the electricity industry and the regulation thereof.

From the contents contained in the consultation document it is not crystal clear as to the timing and timeframe of information that is required – i.e. once every 5 years; is this actual or projected information, quarterly updates annual adjustments etc. As a result thereof a meaningful response cannot be provided as the requirements are too ambiguous at this point in time.

Data must also be reflective of a futures perspective. Current data sets are still very backward looking, and do not reflect the data intensity required for flexibility management, balancing mechanisms, and new technology adoption. These will all impact on the pricing methodology.

b) Stakeholders are requested to comment on the proposed timeframe for licensees to submit their information.

Once the contents and levels of details of the workbooks is known, Eskom would need to undertake a detailed analysis to ascertain whether or not these costs would be available at the lowest levels – i.e., at power station level and whether or not the financial and technical systems are configured to provide the information being sought. It is thus not possible to provide a meaningful response now as the detailed requirements have not been included in this consultation paper.

8.4 Stakeholder Question 4

Please comment on the Role of Energy and Consumer Load Profiles: *a) Are these representative?* *b) Are there others we should consider?* *c) What are your specific needs that should be addressed? Please provide data/evidence of the needs you believe should be addressed.* *d) Is the collection of data a risk to privacy laws? What interventions could be employed to mitigate any risk you believe exists?* *Please comment on the relationship between load and price outlined above concerning the following:* *a) Do you agree with cost reflective tariffs? Please substantiate your answer.* *b) Do you agree with the move away from regulating revenue to regulating prices? Please substantiate your answer.* *c) Do you agree with setting subsidies (where appropriate) based on cost reflective prices? Please substantiate your answer.*

Eskom's Response:

a) Are these representative?

These are not representative and far too generic. There is also very little difference between Load types, 2, 3 and 4 and it not clear how for example, "emergency" power usage will be determined. Further response on the load type is provided later.

b) Are there others we should consider?

The concept of using load types does not make economic sense both for customers and the utility, therefore no suggestion can be provided on others that can be considered.

c) What are your specific needs that should be addressed? Please provide data/evidence of the needs you believe should be addressed

It is not clear what the rate design objective is for this decision, but it's not something that makes sense for residential customers, or even municipalities as they have the peakiest profile and therefore would be allocated the most expensive generation plant costs, or how this proposal would benefit system and grid efficiency improvement.

A flat rate based on someone's load factor is still a flat rate, and there's no signal for anyone to shift behaviour. Without TOU tariffs, customers would have no incentive to reduce load in high-cost peak periods and this would certainly create significant risk for the Eskom system, as customers do and are responding to the TOU signal. The Eskom System Operator requires TOU tariffs the absence of a market (this is normal in any jurisdiction).

This concept ignores that usage is not only dependent on supply but also other factors like commodity prices, country risk, etc. and this will impact the proposed load profile types and customer usage patterns. It also does not take account the behavioural shift of customers to prosumers, whilst still being grid-tied. The ensuing impact on generation in the country of this is huge. The mass rollout of electric vehicle technology as an example, without a clear tariff (TOU) or market-based signal, will create havoc on the ability of Distributors to manage their networks.

There are significant implementation challenges with what is being proposed and the methodology does not address how this will be implemented. NERSA would have to explain, for example in its methodology the following:

- Would NERSA be the party determining which customer would fit into which load type category? What mechanism would be in place if customers load type changed?

- Would NERSA be the party that would set the WAT and if so, what would be the basis for setting this, especially as the method ignores marginal costing.
- This methodology replaces TOU as a driver at the wholesale level, therefore under which load type would Eskom Distribution or municipalities be categorised at a buyer of energy?
- Are these load types based on hourly, daily, weekly, yearly load types?
- Will the allocation of customers into the load categories be based on history or a forecast? What happens if this changes?
- How will abuse or disputes be handled? Which authority will deal with these and where are the rules?
- How will Eskom Distribution or municipalities be able to pass these different load types and their corresponding WAT to end use customers?
- Would there be any cost-recovery mechanism if Eskom Distribution or municipalities is buying under one load type but forced to sell at another load type?

d) Is the collection of data a risk to privacy laws? What interventions could be employed to mitigate any risk you believe exists?

NERSA is advised to take the conditions of the POPIA (Protection of Personal Information Act) into account. Any entity or business cannot divulge a customer's personal information without the customer's consent. This is not just a customer's name and residential address. This applies to a customer's consumption pattern as well. It is personal or specific to the customer which makes an individual customer distinguishable from all other customers.

Second part

a) Do you agree with cost reflective tariffs? Please substantiate your answer.

Yes, as this complies with the EPP and the Tariffs Codes. Eskom has always supported cost-reflective tariff from a level and a structural perspective. Using load profile types to determine costs is against this principle as it does not reflect the system costs at the time of consumption.

However, while cost-reflectivity is important, but must be seen against the backdrop of the topology of the networks that Eskom controls, together with the massive social burden that is placed on customers where great inequality exists between users.

b) Do you agree with the move away from regulating revenue to regulating prices

No, this concept is against any regulatory best practice and places Eskom and municipal licensees under significant financial risk. It is a requirement of the ERA that NERSA is required to comply with.

c) Do you agree with setting subsidies (where appropriate) based on cost reflective prices? Please substantiate your answer.

Guidance should be taken from relevant policy and legislation

8.5 Stakeholder question: 5

a) Do you have anything to add to the Load analysis above? Please comment on your answer. *b) Do you agree with the four loads outlined? Please comment on your answer.* *c) NERSA will need significant data. Large users will often have detailed information available, but for most customers, anticipates collecting this data from the roll-out of smart meters. Do you think this is a reliable source of data? Please comment on your answer.* *d) Large users are aware of the impact of their load on operations for themselves and suppliers, However, South African are generally aware of the power usage in terms of the monthly bill, but often have a very weak understanding of how their loads define their demand profile. It has been postulated that NERSA could have a portal where consumers could calculate their energy usage and subsequent loads types the impose on the system. How do we increase awareness of electricity usage? What other options are available to advocate for greater awareness?* *e) For those consumers that do not have smart meters and it is uneconomic to install such meters (either for the consumer (eg. households) or the supplier) the concept of a benchmark demand profile is being considered as a proxy for the actual the loads consumed. Do you agree with this approach? Is there a better approach?* *f) NERSA will prepare rules on the provision of data (much as it has for licensees) but this will be novel for consumers. What constraints do you foresee in providing data to NERSA for setting electricity prices that are fair and transparent and cost reflective?* *g) Energy demand surveys have postulated as an option to obtain data. What other sources of data would be a reasonable substitute for smart meters?*

Eskom's Response:

a) Do you have anything to add to the Load analysis above? Please comment on your answer.

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.

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 5: Variations in hourly demand

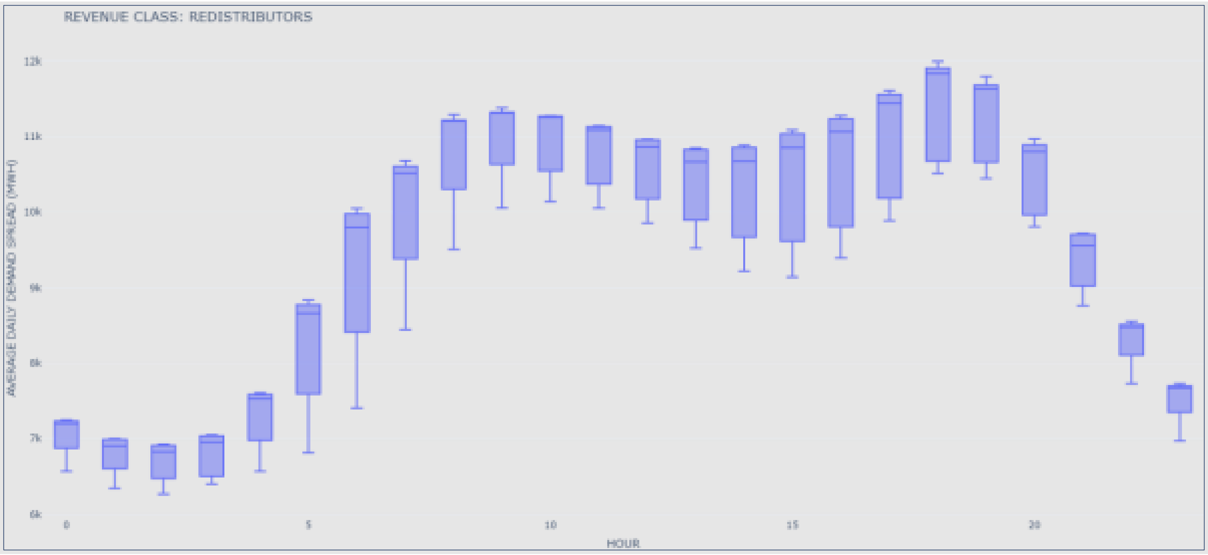
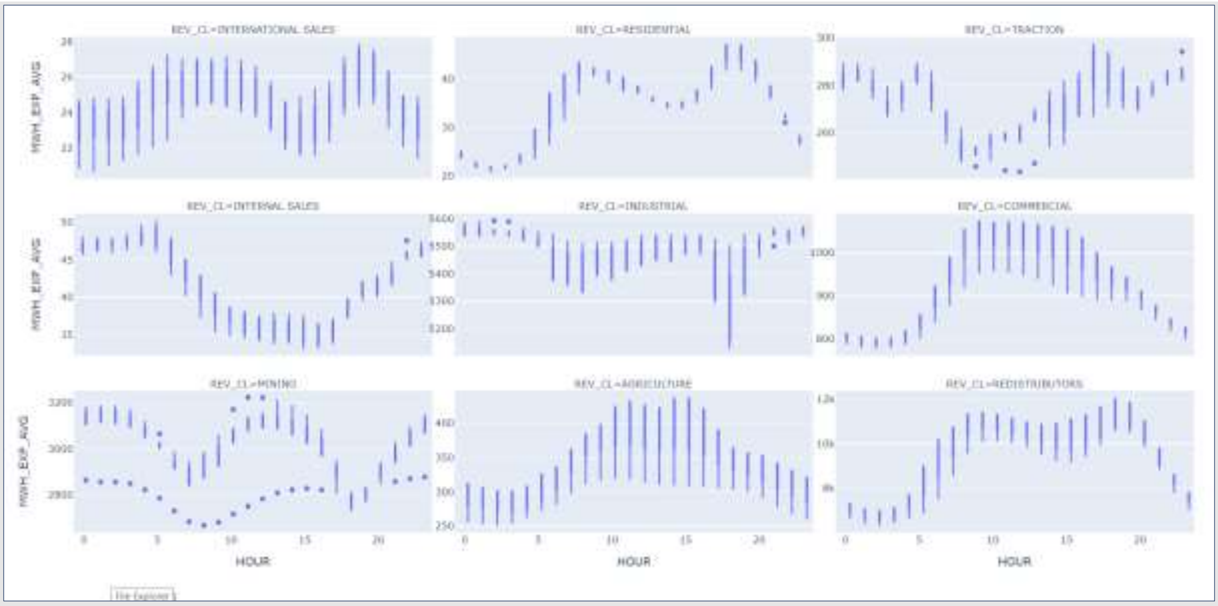


Figure 6: Variations in hourly demands that occur for each of the customer profiles



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.

b) Do you agree with the four loads outlined? Please comment on your answer.

No, 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. 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.

c) NERSA will need significant data. Large users will often have detailed information available, but for most customers, anticipates collecting this data from the roll-out of smart meters. Do you think this is a reliable source of data? Please comment on your answer.

This is a matter that is between NERSA and customers and does not involve the Licensees.

d) Large users are aware of the impact of their load on operations for themselves and suppliers, However, South African are generally aware of the power usage in terms of the monthly bill, but often have a very weak understanding of how their loads define their demand profile. It has been postulated that NERSA could have a portal where consumers could calculate their energy usage and subsequent loads types they impose on the system. How do we increase awareness of electricity usage? What other options are available to advocate for greater awareness?

Customers already have a right to access their load profile information. Such rights are captured in the Codes.

e) For those consumers that do not have smart meters and it is uneconomic to install such meters (either for the consumer (eg. households) or the supplier) the concept of a benchmark demand profile is being considered as a proxy for the actual the loads consumed. Do you agree with this approach? Is there a better approach?

This is a matter that is between NERSA and customers and does not involve the Licensees.

f) NERSA will prepare rules on the provision of data (much as it has for licensees) but this will be novel for consumers. What constraints do you foresee in providing data to NERSA for setting electricity prices that are fair and transparent and cost reflective?

This is a matter that is between NERSA and customers and does not involve the Licensees

g) Energy demand surveys have postulated as an option to obtain data. What other sources of data would be a reasonable substitute for smart meters?

Only meters that provide half-hourly information could be used or properly constituted research studies on an adequate sample size, using feeder data or smart meters installed at customer homes. The cost-benefit of such interventions will need to be considered. Again it is a matter between NERSA and customers.

8.6 Stakeholder question: 6

a) Do you believe the concept of the benchmark demand profile is fair? Please comment on your response.
b) Do you believe separate ancillary services tariffs are reasonable? How would they be calculated? Please comment on your response.
c) Do you agree with the concept of the legacy IPP levy to pay for the self-dispatched power? Please comment on your response.
d) Should legacy IPP PPAs with a capacity charge be part of the abovementioned levy? In other words should everyone have to pay for capacity set aside for specific users?
e) How often do you think pricing reviews should be done? What is the reasonableness of monthly, quarterly, bi annually or annual price reviews and why?

Stakeholders are requested to comment on the following:
f) The consumer pricing methodology guidelines.
g) The fairness of the Time-of-Use approach.
h) The fairness of the Type-of-Use approach.
i) The linking of loads to the economic cost of consumption, as the foundation for electricity prices, is intended to send the correct signals to consumers that will enable them to make informed choices about their energy consumption. Do you agree with this approach and what other signals could be used to achieve this outcome?
j) What other approaches could be considered to send the correct pricing signals to those whose loads require appropriate technologies to cost effectively meet their demand cost-effectively.
k) Whether the approach to mimic market forces in determining electricity prices is fair or not? Please comment on your response.
l) What other options should be considered for rewarding loads shifted to a lower price load as a positive behaviour change from the price signals?

Eskom's Response:

a) Do you believe the concept of the benchmark demand profile is fair? Please comment on your response.

If benchmarking is used it would have to be based on a research study that contains a representative sample of the customer category. This would require smart metering to be installed and the cost of the research study to be funded by NERSA, including the appointment of subject matter experts and statisticians. Also, the sampling would have to take into account that load profiles could differ in different parts of the country, for example the load profiles for a customer in Durban will be very different from a load profile in Johannesburg. Therefore, this research would have to cover the entire country.

Benchmarking still presumes a load profile only. Energy Efficiency measure would be discouraged, and the impact of SSEG integration would thus be negated, unless the customer would then migrate to a differing profile that would match the technology options installed. It is also based on a premise that energy availability is always there.

b) Do you believe separate ancillary services tariffs are reasonable? How would they be calculated? Please comment on your response.

The prevailing policy should be adhered to.

c) Do you agree with the concept of the legacy IPP levy to pay for the self-dispatched power? Please comment on your response.

The electricity industry has not been restructured as yet. The prevailing policy and legislation should apply. There are no legacy IPPs. Current contractual arrangements should be honoured.

d) Should legacy IPP PPAs with a capacity charge be part of the abovementioned levy? In other words should everyone have to pay for capacity set aside for specific users?

Same as above.

e) How often do you think pricing reviews should be done? What is the reasonableness of monthly, quarterly, bi-annually or annual price reviews and why?

The consultation paper is not complete and hence we cannot provide a response as it is not known how revenue applications will be made to NERSA.

Stakeholders are requested to comment on the following:

f) The consumer pricing methodology guidelines.

Reference should be made to the Cost to Serve studies and the current ERTSA process.

g) The fairness of the Time-of-Use approach.

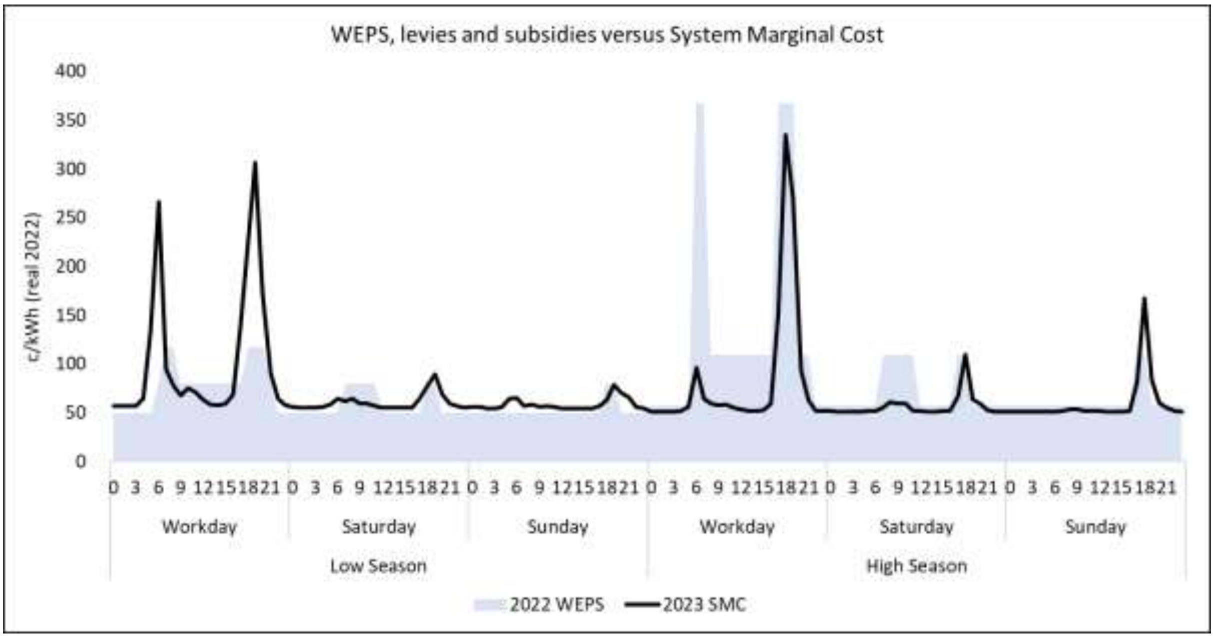
TOU tariffs are needed in the absence of a market. They provide signals aligned with short-run marginal costs and assist the system operator in managing the system. Therefore, TOU tariffs are needed as a proxy for marginal costs and to provide pricing signals to customers to assist the system operator with higher prices in peak periods and lower prices in off-peak and standard periods.

This also provides incentives to customers to save if they shift load TOU tariffs provide the lowest prices for high load factor customers with a flat load profile, as the TOU rates are spread across all time periods, including the cheapest off-peak periods. Therefore, under TOU tariffs higher load factor consumers are still very likely to have lower overall average costs/kWh so these customers are still getting a benefit, but then have the motivation to move high costs kWh to low-cost kWh. Under TOU, the higher load factor customers therefore will have lower overall average costs/kWh so these customers are still getting a benefit, but then have the motivation to move high costs kWh to low cost kWh.

So, both customers and Eskom get the benefit while still meeting what might be seen as the objective of the load factor pricing. This time-differentiated allocation of all costs (investment costs, maintenance costs, fuel costs) provides a more accurate tracking of costs of all types to the consumption it serves.

The TOU tariff certainly more accurately reflects system marginal costs than a type of use tariff approach. The following describes this alignment.

Figure 7: Comparison between System Marginal Cost (SMC) and TOU tariff (without losses, levies, and subsidies)



The following can be observed:

1. There is a reasonable correlation between the TOU tariff profile and the system marginal cost (SMC) profile but there are clearly also some exceptions. Eskom's intent in its retail tariff plan aims to restructure the TOU.
2. TOU tariff charges are higher than the SMCs in the peak and standard periods during the winter months except for Sunday evenings. This reflects the fact that Eskom recovers not only its variable cost but also a large portion of the fixed generation cost via the TOU rates during these times. In fact, it could be argued that Eskom's TOU rates in the morning peak and in the standard periods in the high season are too high.
3. However, what is of concern is that Eskom appears to sell off-peak electricity in the low season period below the marginal cost of supply. It means that incremental electricity sold during these periods not only fail to recover the marginal cost of production, but these sales do not make any contribution towards the recovery of Eskom's capital costs.

Another important point to highlight is the recovery of Generation's fixed costs hinges on high-price energy sales for a few peak and standard hour sales during the high season. This exposes Generation's revenue requirement to significant volume risk.

h) The fairness of the Type-of-Use approach.

It is inherently unfair, not implementable and is not a proxy or a precursor for a market. This premise that it is a proxy for a market by NERSA is fundamentally flawed.

This approach of allocating the cheapest generation to baseload customers seems to be 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. The assumption that baseload generators are the cheapest to run from a marginal cost perspective is incorrect.

Even if some customers have a steady flat demand and others have a specific peak period demand, the causal responsibility for peak capacity rests on all types of customers consuming in a peak hour.

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 as discussed in the Data Gathering chapter. 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 would be, needs to be considered.

This also raises another question, how static or dynamic is the load type allocation? This allocation system assumes that customer demand profiles are static. Comparing high- and low-season customer demand profiles one quickly finds that this is not the case.

This approach was considered in the USA (referred to as the decomposition method of allocating generation cost) and rejected for the reasons given above. 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

This document states

"The decomposition approach conflicts with reality in many ways, including:

1. The reserve requirements for the decomposed systems would be driven by their noncoincident class peaks or high loads (if they are assumed to be fully free-standing), requiring additional hypothetical capacity for utilities that are not already extensively overbuilt. If the decomposition assumes that the multiple class-specific systems would operate in a power pool, contribution to the system peaks would drive capacity requirements.

2. A system with a high load factor and relatively few large units would require a very high reserve margin (as discussed in Subsection 5.1.1) to cover fixed outages and even maintenance outages. The reserve units would operate in many hours (since the system load would A baseload-only system would require a large amount of backup supply energy, either from hypothetical units or as purchases from the other classes.

4. The decomposition approach is usually designed to assign the lowest-cost resources to the industrial class, always be near the allocated baseload capacity). shifting all the costs of mistakes and market changes onto the other classes. That includes excess capacity (even excess baseload and capacity made excess by decline in industrial loads), the costs of fuel conversion and the high costs of plants built as baseload but currently operated as peakers.

5. It is not clear how variable renewables and other unconventional resources would be incorporated into the decomposed utility systems.

It is possible (if not certain) that the decomposition approach could be expanded and revised to create a viable classification and allocation method, but at this point no such model has been developed.

A decomposition method that accounts for all relevant factors may not show an advantage for industrial customers. In Alberta, a related method to the decomposition method was presented to demonstrate that baseload power for industrial customers would be considerably more expensive than the demand-based cost allocation of the existing system for the industrial class (Marcus, 1987)."

i) The linking of loads to the economic cost of consumption, as the foundation for electricity prices, is intended to send the correct signals to consumers that will enable them to make informed choices about their energy consumption. Do you agree with this approach and what other signals could be used to achieve this outcome?

It is not possible to price in an environment where prices are based on economic cost of consumption. Even in a competitive pricing environment, pricing always starts with understanding of costs.

j) What other approaches could be considered to send the correct pricing signals to those whose loads require appropriate technologies to cost effectively meet their demand cost-effectively.

TOU tariffs are suitable and then moving in the future to market-based pricing.

k) Whether the approach to mimic market forces in determining electricity prices is fair or not? Please comment on your response.

The proposed approach does not mimic market forces in any way or form. Allocating specific generator costs to specific customer load types do not reflect the system costs and is totally against the way a market would work.

l) What other options should be considered for rewarding loads shifted to a lower price load as a positive behaviour change from the price signals?

TOU tariff are suitable and then moving in the future to market-based pricing.

Stakeholder Questions: Annexure E – Detailed Workbook Structures

Reference is made to detailed workbooks, the contents of which are not known at this point in time as it is absent from the consultation paper. The tables contain a mere high-level listing of cost categories, with no detailed explanations as to what this should entail. It is thus envisaged that another consultation with stakeholders will take place so as to afford them an opportunity to meaningfully engage on the contents therein.

In addition, it is not clear from the document what existing requirements will be replaced – i.e. do these detailed workbook structures replace the Minimum Information Requirements for a Tariff Application (MIRTA) etc.

So, at this point in time, it is challenging to provide meaningful responses to the questions raised as the detailed requirements are not available in this consultation paper. It would be best for NERSA to consult on a complete methodology.

In addition, once the specifics are made available to stakeholders, Eskom would need to undertake a detailed analysis to determine whether or not the relevant systems (financial and technical) are configured in a manner that allows that these details are readily available.

8.7 Stakeholder question 1

Stakeholders are requested to comment on generation PowerStation information as detailed in table 2 above. Total nominal capacity will be used as a denominator in determining the tariff.

a) Is the information sufficient to understand general power station information of each power station?

b) Is the use of nominal capacity as a denominator appropriate in tariff determination?

<u>Eskom's Response:</u>

a) Is the information sufficient to understand general power station information of each power station?

No. The information is just a listing, with no details on definitions, costs, etc.

b) Is the use of nominal capacity as a denominator appropriate in tariff determination?

From the information provided, it is not understood how the nominal capacity as a denominator will facilitate a tariff determination. Inadequate information provided to enable a meaningful response.

8.8 Stakeholder question 2

Stakeholders are requested on the content of RAB information required from licensees, as shown in Table 3. NERSA is of the view that an evaluation method other than historical costs should be avoided. *a) Will the information be sufficient for NERSA to understand costs related to RAB for tariff determination? If not, what other information could be included?* *b) Should a licensee be granted freedom to choose its preferred approach, and what is the most appropriate evaluation approach?*

<u>Eskom's Response:</u>

a) Determination of the RAB

No, the information is not sufficient. The prevailing legislative framework must be adhered to. The requirements as set out in the current EPP (2008) in so far as the asset valuation methodology is as follows:

Policy Position: 1
*a) 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. <u>The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that</u> <u>**accurately reflects the replacement value of those assets** such as to allow the electricity utility to obtain reasonably priced funding for investment; to meet Government defined economic growth.</u>* *b) In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator,*

<u>Hence replacement value and not historic cost as alluded to by NERSA in this consultation must be used to determine the RAB in line with the existing legislation</u>.

b) Should a licensee be granted freedom to choose its preferred approach, and what is the most appropriate evaluation approach?

In order to ensure fair and equitable treatment of all Licensees, it is proposed that the asset valuation methodology should be standardised, and it should accurately reflect the replacement value of the assets.

8.9 Stakeholder question 3

Stakeholders are requested to comment on the details and the format of information regarding primary energy required from licensees and the fact that this information is required for each power station.

<u>Eskom's Response:</u>

Mention is made of two generation workbooks – one for any generator (including IPPs) and one that is Eskom specific. These two workbooks have not been shared as part of the consultation process.

Once the contents and levels of details of the workbooks is known, Eskom would need to undertake a detailed analysis to ascertain whether or not these costs would be available at the lowest levels – i.e. at power station level and whether or not the financial and technical systems are configured to provide the information being sought.

8.10 Stakeholder question 4

Licensees are requested to comment on the format and details contained in table 6 above on relating to operation and maintenance. *a) Is the information required on from licensee sufficient and appropriate to have full underrating of the costs and for tariff setting purpose?*

<u>Eskom's Response:</u>

The text contained in the document seems to suggest that operations and maintenance costs are variable in nature. This is not necessarily the case, in fact, a large proportion of the operations and maintenance costs are fixed in nature.

The table contained in the consultation paper provides a mere listing of items that make up operations and maintenance. There are no definitions of what is required and no indication of the level of detail that needs to be provided.

The categories of costs may also differ across power stations as there are different technologies employed. In addition, the current financial systems are also not set-up to collect these specific cost buckets.

It is envisaged that once NERSA has developed the specifics (including said workbooks etc.) of what is required, stakeholders will be engaged and consulted so a detailed analysis can be done to assess what would be feasible, including an assessment of the impact on current processes and systems.

As a result of the lack of information contained in the consultation document, Eskom cannot provide a meaningful comment that would assist in enhancing the document. Eskom will gladly participate and contribute once the details are known.

8.11 Stakeholder question 5

NERSA requires shared cooperated costs information to understand licensees' operations. *a) Stakeholders are requested to comment on details and information relating to the other support and shared costs as detailed in table 6 above.* *b) Is the information required from licensees sufficient and appropriate for tariff setting purpose? Please provide any other additional information that may be necessary.*

Eskom's Response:

Shared Corporate costs - It is unclear from the information contained in the consultation paper as to what is being referred to as "Corporate" – i.e. the Definition of Corporate has not been provided. Is reference being made to Eskom Corporate vs "Head Office Function in the Licensees"?

This clarification would need to be provided in order to be in a position to make an assessment of what is required.

8.12 Stakeholder question 6

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail? *b) Should the IPP information be part of the TSO or should it be captured with Eskom Generation information?* *c) How should the fixed costs be allocated to the different customer group, should they be shared equally or be based on customer's level consumed capacity?* *d) Transmission costs are largely fixed in that they are not linked to what is produced. How can the charges associated with these fixed costs be allocated, (e.g. R/MVA, R/MW, and R/km)?*

Eskom's Response:

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail?

Clarification is required on what is required differently between Tables 8 and 9. In terms of Table 8, the data as required can be provided. With respect to Tables 8, 9 and 11, it needs to be noted that individual IPP information could be confidential as per contract requirements.

b) In terms of the prevailing methodology; IPPs are included as part of the Generation costs. However, it is envisaged that in the proposed model, these would be included as part of the Market Operator costs within the National Transmission Company.

The IPP information should be provided for in accordance with the prevailing policy and legislation and future allocation will be guided by the revised ERA and EPP.

c) How should the fixed costs be allocated to the different customer group, should they be shared equally or be based on customer's level consumed capacity?

Fixed costs should be recovered as far as possible through fixed charges. Depending on the service provided, the fixed costs should be allocation based on the cost driver. For generation the cost driver is marginal cost for fuel and fixed costs for generation capacity, for networks the cost driver is demand (capacity installed to meet the load) or export capacity (capacity installed to meet the export capacity for generators), and for retail costs, the cost driver is the size of the supply to the customer (larger customers get more individualised service)

d) Transmission costs are largely fixed in that they are not linked to what is produced. How can the charges associated with these fixed costs be allocated, (e.g. R/MVA, R/MW, and R/km)?

The transmission costs are fixed and there is a link to what is produced based on the maximum export capacity of the generators and the reserve capacity required by loads. The cost driver for the transmission grid is therefore peak capacity and not energy, thus the charging for should be fixed, i.e. the charge out structure should be R/MVA for loads and R/MW for generators.

Both the distance (location) relative to load centres and capacity of the plant are important and there are methods that are able to consider both in determining the network and losses charges. The current zonal method as per the existing South African Grid Code (Transmission

Tariff Code) considers both the capacity and location of the generation plant in determining the charges. It is recommended that these principles be retained.

The losses are a function of energy and dispatch patterns, thus the charge out structure should be c/kWh based on based on average loss factor, charged to both loads and generators. Ancillary services can be both R/kVA and c/kwh and charges out to both generators and loads.

8.13 Stakeholder Question 7

a) What is the most appropriate way of valuing asset value?
b) How can the efficiency of capital investment be taken into account?
c) Is there value in categorising the Tx infrastructure according to zones as well as voltage levels, is it practical or desirable?
d) How should the fixed cost be allocated to the different customer group, should they be shared equally or be based on customer's level consumed capacity?
e) Transmission costs are largely fixed in that they are not link to what is produced. How can the charges associated with these fixed costs be allocated, (e.g. R/MVA, R/MW, R/km)?

Eskom's Response:

a) What is the most appropriate way of valuing asset value?

The most appropriate valuation method is to utilise the MEAV (i.e. Modern Equivalent Assets Valuation) in terms of the costs to replace the assets with a modern equivalent and adjust for the remaining life to reflect physical, functional and technical obsolescence. This method is utilised by Energy Regulators in other jurisdictions. The valuation is conducted by an independent valuator and therefore free from any influence by the utility. An advantage of using the MEAV approach is that it ensures that any historical capital cost inefficiencies are not used to determine future returns. It enables the Regulator to be able to consider whether the original investment was efficient when compared to a modern equivalent of the same asset.

Transmission is mostly a capital intensive business and its assets can be described as specialised assets in terms of the International Valuation Standards (IVS) as they are rarely, if ever, traded in the market due to their uniqueness arising from usage, design, configuration, size and location. According to same standards ("IVS"), the cost approach valuation which is applied through the depreciated replacement cost technique is the most acceptable method when valuing a specialised assets such as the ones found in Transmission where there is little or no comparable market evidence to estimate their values.

The total assets valuation should comprise of the following components:

- Depreciated Replacement Cost (DRC) of the existing fixed assets and adjusted for the remaining life and technical obsolescence.
- New commissioned assets being assets transferred into Commercial Operation subsequent to the asset valuation and be adjusted for the remaining life.
- Work Under Construction (WUC) which refers to the capital project expenditures or WUC values (excluding IDC) incurred prior to the assets being placed in Commercial Operation (CO).

b) How can the efficiency of capital investment be taken into account?

NERSA is advised to refer to its Prudency Guidelines. Compliance to the grid code investment criteria, based on prudent least life cycle costs should be taken into account.

c) Is there value in categorising the Tx infrastructure according to zones as well as voltage levels, is it practical or desirable?

Yes, Transmission charges should be aggregated / categorised into zones to encourage price stability, cost reflectivity and simplicity. The existing Transmission zonal tariffs for loads are based on postage-based principles and the zones for generators consider both geographical location and electrical proximity of the generator to loads. It is anticipated that the generation centres will shift in the future which will require a dynamic approach to review the zones to cater for this shift as well as to provide for the Transmission investment that will have to be required to establish the infrastructure to evacuate the power from new generation resources.

It is not practical or desirable to categorise the ancillary services costs according to zones or voltage levels and the benefits of doing so are not known

Transmission use of system (TUOS) tariffs for generators are derived from load-flow simulations on the Transmission system as it is planned to be in operation. The charging methodology only recognises peak security as a driver of network usage and assumes that all types of generation within an area of the network (a generation charging zone) contribute equally to network use. In doing so, it overlooks the fact that some generators use the Transmission system more during the peak hours and some less. Under the current methodology, all types of generators are assumed to provide peak security.

The transmission capacity, location and usage are important cost drivers for Transmission investments. The zonal pricing provides stability and predictability of prices as it provides average prices per zone that can remain stable unless major changes to the network occur.

d) How should the fixed cost be allocated to the different customer group, should they be shared equally or be based on customer's level consumed capacity?

Fixed cost should as far as possible be based on the demand (loads) or export capacity (generators).

e) Transmission costs are largely fixed in that they are not link to what is produced. How can the charges associated with these fixed costs be allocated, (e.g. R/MVA, R/MW, R/km)?

The transmission costs are fixed and there is a link to what is produced based on the maximum export capacity of the generators and the reserve capacity required by loads. The cost driver for the transmission grid is therefore peak capacity and not energy, thus the charging for should be fixed, i.e. the charge out structure should be R/MVA for loads and R/MW for generators.

Both the distance (location) relative to load centres and capacity of the plant are important and there are methods that are able to consider both in determining the network and losses charges. The current zonal method as per the existing South African Grid Code (Transmission Tariff Code) considers both the capacity and location of the generation plant in determining the charges. It is recommended that these principles be retained.

The losses are a function of energy and dispatch patterns, thus the charge out structure should be c/kWh based on based on average loss factor, charged to both loads and generators. Ancillary services can be both R/kVA and c/kwh and charges out to both generators and loads.

8.14 Stakeholder question 9

a) How can the efficiency of operation and maintenance cost be taken into account.

<u>Eskom's Response:</u>

NERSA is encouraged to make reference to its "Guidelines for Prudency Assessment" it developed in 2018 to provide an insight to Licensees on how NERSA conducts its assessment of the costs to determine prudency.

8.15 Stakeholder question 10

a) Can ancillary services be apportioned to a particular consumer group? *b) If yes above, how should ancillary services be charged to different customer groups? Should these cost be socialised to the entire customer base? Which customer group creates the need for ancillary services?* *c) Does the list above covering all currently deployed ancillary services?* *d) Is it likely that there may be additional types of ancillary services that are not included in the list above that would need to be catered for in the future?*

Eskom's Response:

a) Can ancillary services be apportioned to a particular consumer group?

Ancillary services is sourced from supply and demand side, hence it's inclusive of both generation and demand. End-user ultimately pays via the tariff. Hence it cannot be proportioned to a particular consumer group. All customers should have ancillary services (AS) allocated to them.

The challenge with allocating AS per customer group is that most of the services benefit all customers equally. Additionally AS services that support the energy mix that predominantly comprises of renewable technologies also benefit all customers.

Extensive studies will be required to establish the basis for distinguishing the changes that are to be apportioned to customer groups. It is better to have the uniform prices to all customer in the current setting.

b) If yes above, how should ancillary services be charged to different customer groups? Should this cost be socialised to the entire customer base? Which customer group creates the need for ancillary services?

Ancillary services are necessary for grid stability to the benefit of all customers. A uniform charge to all customers works out better. More information and time is required in order to investigate further. The ancillary services products are available to all who meet the criteria.

Note that all customer groups benefit from the provision of ancillary services, thus all customer groups create the need for Ancillary Services. NERSA to clarify what is meant by socialised? Is the question aimed specifically at demand response? Further clarifications are required.

c) Does the list above covering all currently deployed ancillary services?

Yes, it covers all AS products currently in existence, however provision should be made for more categories of AS products, because there is an intention to expand the range and quantity and thus it should not be limited to what is there now, but rather to allow for the provision of more products. NERSA to advise how AS related expenses related to fines e.g. a SAPP penalty fine due to poor provision of reserves from generation are to be treated? Would this be included as a reserves related ancillary services cost linked to generation?

d) Is it likely that there may be additional types of ancillary services that are not included in the list above that would need to be catered for in the future?

Yes, the system operator is researching new ancillary services that may be beneficial to the system e.g. fast frequency response reserves, self-start restoration services, inertia support etc. and thus provision should be made for the inclusion of new service and product offerings.

8.16 Stakeholder question 11

Should the System and Market operator be allowed a profit/margin?

Eskom's Response:

The ERA and EPP are currently under review and it is envisaged that these will pave the way forward on the proposed market structure. At present, Eskom has a single Transmission License and earns a return on its assets.

8.17 Stakeholder question 12

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail? *b) What costs is a Market Operator likely to have? Is it your view that the future Electricity Industry structure will have a Market Operator separated from the Independent System Operator?*

Eskom's Response:

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail?

Need a better understanding of the ABC requirements and impact to determine if it is implementable or not. Note dependency on being able to obtain required information from Generation, IPP and other relevant value chain participants. It will also be impacted by any changes to the AS costing methodologies and the introduction of new AS products. Note that AS revenue requirements (and resulting AS charges) could increase significantly as we transition to an AS market. These will also be dynamic in nature depending on existing circumstance and availability of plant for AS.

b) What costs is a Market Operator likely to have? Is it your view that the future Electricity Industry structure will have a Market Operator separated from the Independent System Operator?

Eskom has provided commentary to both the ERA and EPP that is being reviewed and that deals with issues related to the future structure of the electricity industry. These discussions are best placed in the policy environment and do not fall within the ambit of NERSA. Hence it is best these get dealt with there.

8.18 Stakeholder Question 13

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail? *b) Are there other ancillary services that would be required in the near future that are not listed above?*

Eskom's Response:

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail?

Same as response to Stakeholder Question 12 a. Need a better understanding of the ABC requirements and impact to determine if it is implementable or not. Note dependency on being able to obtain required information from Gx, IPP and other relevant value chain participants. It will also be impacted by any changes to the AS costing methodologies and the introduction of new AS products. Note that AS revenue requirements (and resulting AS charges) could increase significantly as we transition to an AS market.

b) Are there other ancillary services that would be required in the near future that are not listed above?

See response to Stakeholder Question 10 d. Yes, SO is researching new ancillary services that may be beneficial to the system e.g. fast frequency response reserves, self-start restoration services, inertia support etc. and thus provision should be made for the inclusion of new service and product offerings. This will also be largely dependent on new technology becoming available e.g. grid forming invertors.

8.19 Stakeholder question: 14

a) Should municipal distribution network charges that are different from Eskom network tariffs be allowed? *b) What other options for designing network tariffs should be considered by NERSA?* *c) Stakeholders are requested to comment on the proposed approach to recovering the cost of distribution network services from traders.*

Eskom's Response:

a) Should municipal distribution network charges that are different from Eskom network tariffs be allowed?

If the premise is that network charges are based on the costs of operation, maintaining and refurbishing network, then each licensees will have their own costs, their own demographics, their own unique customer base, therefore they cannot all have the same tariffs. However, the structure and methodology for these tariffs to be designed should be the same. This is aligned to the EPP.

b) What other options for designing network tariffs should be considered by NERSA?

See above

c) Stakeholders are requested to comment on the proposed approach to recovering the cost of distribution network services from traders.

All licensees that are retailers with regulated tariffs, that use the electricity grid, should pay for the use of the grid. Traders that perform only a trading function are not customers of the licensee, only the customers connected to the grid should pay for network services

8.20 Stakeholder question: 15

Stakeholders are requested to comment on how the energy losses in the distribution system should be determined?

Eskom's Response:

Distribution energy losses is the difference between what is purchased (injected into distribution networks) and what is sold/served to all Distribution customers. This figure represents total losses i.e. technical and non-technical losses combined. Global benchmarks are done on the total losses for all utilities. These should be combined.

8.21 Stakeholder question: 16

Stakeholders are requested to comment on the principles to be considered for the treatment of existing wheeling arrangements.

Eskom's Response:

Wheeling charges are standard use of system tariff charges. Per the ERA, the Licenses and the EPP non-discriminatory access must be provided and therefore irrespective from whom the energy is wheeled the same charges should apply. This requires proper unbundled use of system charges.

The EPP also makes it clear that no additional charges should be raised unless there are additional costs. This cost would only be the cost of administration.

8.22 Stakeholder question: 17

a) Should licensees be given freedom to choose a method of valuing RAB or should NERSA prescribe an approach? *b) Should a prescribed approach be preferred; which approach is the most practical for implementation in South Africa.*

Eskom's Response:

The current legislative framework must be adhered to. The requirements as set out in the current EPP (2008) in so far as the asset valuation methodology is as follows:

Policy Position: 1
*a) 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. The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that **accurately reflects the replacement value of those assets** such as to allow the electricity utility to obtain reasonably priced funding for investment; to meet Government defined economic growth.* *b) In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator,*

Hence replacement value and not historic cost as alluded to by NERSA in this consultation must be used to determine the RAB in line with the existing legislation.

In order to ensure fair and equitable treatment of all Licensees, it is proposed that the asset valuation methodology should be standardized and it should accurately reflect the replacement value of the assets.

8.23 Stakeholder question: 18

Stakeholders are requested to comment on the appropriateness of the cost of operations and maintenance of the distribution networks.

Eskom's Response:-

The data required is currently not in the format as prescribed in Annexure E. The process to compile the data will be intense (NERSA's own words in paragraph 6.1.5) and extremely complex. In the absence of detailed workbooks, definitions etc. it is also not possible to provide a meaningful response.

8.24 Stakeholder question: 19

Do you believe that the operating cost categories for other support and share of the corporate division listed above are adequate?

Eskom's Response:

Shared Corporate costs - It is unclear from the information contained in the consultation paper as to what is being referred to as "Corporate" – i.e. the Definition of Corporate has not been provided. Is reference being made to Eskom Corporate vs "Head Office Function in the Licensees"?

8.25 Stakeholder Question: 20

a) Stakeholders are requested to advise if the required information in respect of the trading activities sufficient to carry the required analysis;
b) Stakeholders are requested to clearly identify the costs related to trading activities and separate those costs from the distribution activities.

Eskom's Response:

There is insufficient information on the definition of trading as alluded to in the consultation paper. Hence more information is required in order to respond meaningfully.

8.26 Stakeholder Question: 21

a) Should NERSA set the trading margin or leave it to the market to decide? Or should it set the tariff only if there is no competition? *b) What would be the denominator to translate the costs into a tariff in order to come up with the margin?*

Eskom's Response:

a) Should NERSA set the trading margin or leave it to the market to decide? Or should it set the tariff only if there is no competition?

The revisions of the ERA and EPP are currently underway and we will await the outcomes.

b) What would be the denominator to translate the costs into a tariff in order to come up with the margin?

The revisions of the ERA and EPP are currently underway and we will await the outcomes

8.27 Stakeholder Question: 22

a) Since that trading is not asset based but rather knowledge based, can the financial assets (i.e. IT systems, meters, inventory, bad debts) be used to determine the margin? *b) How should the profit associated with trading be determined?* *c) Should traders be owning the infrastructure they are trading on?* *d) Should licensees be given freedom to choose a method of valuing RAB or should NERSA prescribe an approach?* *e) Should a prescribed approach be preferred, which approach is the most practical for implementation in South Africa?*

Eskom's Response:

(a), (b) and (c) Trading

Guidance should be taken from the revised ERA and EPP that is currently underway. There is insufficient information on the definition of trading as alluded to in the consultation hence more information is required in order to respond meaningfully.

(d) and (e) RAB Related

The prevailing legislative framework must be adhered to. The requirements as set out in the current EPP (2008) in so far as the asset valuation methodology is as follows:

Policy Position: 1
*a) 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. <u>The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that</u> <u>**accurately reflects the replacement value of those assets** such as to allow the electricity utility to obtain reasonably priced funding for investment; to meet Government defined economic growth.</u>*
b) In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator,

<u>Hence replacement value and not historic cost as alluded to by NERSA in this consultation must be used to determine the RAB in line with the existing legislation</u>.

In order to ensure fair and equitable treatment of all Licensees, it is proposed that the asset valuation methodology should be standardized and it should accurately reflect the replacement value of the assets.

8.28 Stakeholder Question: 23

Since trading is not asset based but rather knowledge based; *a) Should the financial assets (i.e. IT systems, meters, inventory, bad debts) be used to determine the margin?* *b) How should the profit associated with trading be determined?* *c) What will be an allowable cost if costs associated with trading are allowed (i.e. bad debts)?* *d) Is it a good incentive for paying customers to be penalised for the rest of the non-paying customers?*

<u>Eskom's Response:</u>

Guidance should be taken from the revised ERA and EPP that is currently underway. There is insufficient information on the definition of trading as alluded to in the consultation paper Hence more information is required in order to respond meaningfully.

8.29 Stakeholder Question: 24

a) What are the unique costs related to trading? For example, hedging and (forward prices) long-term prices with generators. Should the cost of hedging be recognised?

<u>Eskom's Response:</u>

There is currently no market. We will await guidance from the revision of the ERA and EPP.

8.30 Stakeholder question: 25

Based on the split of costs between variable, fixed and classification, stakeholders are requested to comment on the following: *a) Provide your own views on NERSA's list of the classification of the costs into fixed and variable.* *b) How to split of fixed costs or allocation of fixed costs to customers based on consumption?* *c) Under transmission costs comment on which portion of an ancillary service cost can be socialised (out of pocket costs) and which portion can be carried by customers*

Eskom's Response:

a) Provide your own views on NERSA's list of the classification of the costs into fixed and variable.

The list provided at a high level is acceptable

b) How to split of fixed costs or allocation of fixed costs to customers based on consumption?

Fixed costs should be recovered from customers as far as possible through fixed charges based on capacity, not consumption for both generators and loads, but also taking into account the impact on vulnerable customers. However, it not understood what consumption would be used if there is no predetermined sales volume?

c) Under transmission costs comment on which portion of an ancillary service cost can be socialised (out of pocket costs) and which portion can be carried by customers

Possibly the entire AS cost to be carried by the customer as all customers benefit from the provision of ancillary services. Clarification required to understand the differences and implications of costs that are socialised vs carried by the customer.

The cost of ancillary service should be raised from customers on c/kWh and/or R/KVA basis to reflect the cost drivers (technology fixed costs and energy).

A R/kVA charges should also be used to encourage the behind the meter customers to contribute to ancillary services. 100% of the cost can be socialised (allocated equally to all customers) until such time that the extensive studies that demonstrate that there exists a causal link between certain customer groups and AS costs. However from the benefit perspective, our view is that all users benefit from these services.

8.31 Stakeholder question: 26

a) How should NERSA deal with cold-reserved plants and ancillary service costs? *b) How should NERSA work out the tariff when a plant is on call reserve?* *c) There are plants that have interlinked costs such as cost of recharging in the storage facilities. How should NERSA deal with such costs?* *d) In the Gx, Tx and Dx tariffing how should NERSA deal with wheeling charges.* *e) Transmission is composed of system and market operation. How should NERSA set a transmission tariff to achieve a single-transmission tariff?* *f) Stakeholders are requested to comment on the tariff strictures listed above for each business activities within the value chain.* *g) Please comment on the fairness and justification of allocating capacity costs/charges to consumers based on their demand and provide an alternative.* *h) How do we allocate the energy costs to customers based on a R/day per consumer?* *i) How can transmission costs be allocated in a manner that is fair?* *j) Should NERSA set the trading tariffs, explain why?* *k) NERSA's view is to review tariffs every quarter. What is the period to review the licensees' tariffs? In addition, explain the rationale for the proposed time frame.*

<u>Eskom's Response:</u>

a) How should NERSA deal with cold-reserved plants and ancillary service costs?

If a cold reserve unit is AS and grid code certified, then the associated AS cost should be included similar to other AS providers. Clarification is required on whether or not SO and AS costs included in this formula? Or is this formula specific to the Tx network provider (Tx Grids)?

b) How should NERSA work out the tariff when a plant is on call reserve?

Cold reserve generators are those capable of starting up within a short instruction period (as opposed to those in long term storage which have limited capability of starting up within 12 months) The fixed costs of these cold reserve generators should be recovered in the same way as online generators as they are available for startup as required.

c) There are plants that have interlinked costs such as cost of recharging in the storage facilities. How should NERSA deal with such costs?

The variable cost of generation required for charging / pumping should be passed to these generators as their input cost, along with a concomitant revenue for energy output which reflects the cycle efficiency of the storage facility. This effectively ensures that the energy input and costs are netted off and the net cost of the facility is carried in the capacity and ancillary services revenue for the facility.

d) In the Gx, Tx and Dx tariffing how should NERSA deal with wheeling charges.

Eskom wheels energy to all its customers (loads and generators) whether energy is supplied by Eskom or through a third party wheeling transaction. Wheeling charges are standard use-of-system (network and retail) charges, and a customer that is in a third party wheeling transaction should not avoid making a contribution to NERSA approved subsidies. There should be no additional charges for third party wheeling except for the additional cost of administration. Eskom's wheeling charges are standard charges for all customers.

e) Transmission is composed of system and market operation. How should NERSA set a transmission tariff to achieve a single-transmission tariff?

Will await guidance from the revised EPP.

f) Stakeholders are requested to comment on the tariff strictures listed above for each business activities within the value chain.

The Distribution and Transmission tariffs codes and EPP adequately describe tariff structures that can be used.

It is not clear, however whether the Generation tariff is a single rate or rates based on the WAT, that is, 4 different rates as described NERSA proposed "structures" and how the R/kVA (should be R/kW) generation capacity charge fits into the WAT formula. The method proposed by NERSA seen to imply that there is no wholesale purchase price and that the generator costs are converted into a tariff and this tariff is then paid by the end consumer.

Also ancillary service charges are missing from the formula.

g) Please comment on the fairness and justification of allocating capacity costs/charges to consumers based on their demand and provide an alternative.

Cost should be allocated on the cost-driver. If the cost driver is creating and reserving capacity to meet the customer's demand, then costs should be allocated on such capacity

h) How do we allocate the energy costs to customers based on a R/day per consumer?

This should only ever be done in cases where metering is not used (like street lighting or very low consumption supplies). Using a R/day approach does not provide customers with appropriate signals for their usage and creates subsidies where low consumption customers subsidise high consumption customers. This is not supported.

i) How can transmission costs be allocated in a manner that is fair?

Transmission costs should separate connection costs from use of systems (operational etc.) costs. The connection charging methodology should also ensure that customer pay for their share of the costs. The transmission usage costs should comprise locational component and non-locational components (socialised). The locational (and zonal) methodologies noted in response to question 6 above provide for a fair technique that links network usage to the generators.

For load customers, a different zoning method is likely to introduce price differences for similar customers and may affect how distributors set their pricing. A postage stamp method seems fairer for load customers. Refer further to the Transmission tariff code and the EPP.

j) Should NERSA set the trading tariffs, explain why?

NERSA should only regulate retail charges raised by licensees. For unregulated bilateral trading this has nothing to do with NERSA.

k) NERSA's view is to review tariffs every quarter. What is the period to review the licensees' tariffs? In addition, explain the rationale for the proposed time frame.

It is not clear how this would be applied to licensees and customers and does not take into account the requirements of the MFMA. NERSA needs to take cognisance of other legislative requirements, such as the MFMA. As it stands at the moment, NERSA will not be enabled to review tariffs on a quarterly basis. The law of the country does not allow for such a proposal to be made.

8.32 Stakeholder Question 26

Stakeholders are asked to consider the aforementioned tariff options and respond to the following questions accordingly:

a) Transmission tariffs that reflect both the capacity and the distance are being considered. Do you agree with the transmission tariffs that reflect both aspects?

b) Are transmission zones an appropriate mechanism, considering that today energy is injected into the grid from across South Africa?

c) Distribution tariffs that reflect both the capacity and the distance are being considered. Do you agree with the transmission tariffs that reflect both aspects?

d) Should municipalities have exclusive right to trade in demarcated municipal boundaries?

Eskom's Response:

a) Transmission tariffs that reflect both the capacity and the distance are being considered. Do you agree with the transmission tariffs that reflect both aspects?

Note SO cost in R/kWh/km – does this include the ancillary services costs? Clarification is required?

Locational (nodal prices) include both and are key in supporting the efficient usage of the transmission system. Location is important to signal to the customer when the costs of using the system may be lower beneficial for the customer to connect. The methodology for allocating transmission cost is contained in the Transmission Tariff Code. The cost driver for Transmission is capacity (system peak of locational peak due to the penetration of renewable technologies. The pricing methodology for generators and loads should be aligned and consider evolved to consider the integration of renewable generation.

The charges should be allocated by on the capacity requirement and contribution to peak power flows. Solar PV contributes to peak power flows during the day, where as other customer categories contribute to peak power flows in the evening.

Generators located far from consumption centres require transmission infrastructure to be built to deliver energy, increase network losses and negatively impact the economic efficiency of the power system resulting in increased overall costs. One way to reduce such costs is to provide locational signals to incentivise generation assets and end users to be sited closer to each other. Such locational signals can be applied to generators and to consumers. This means that investments in generation, loads and grid infrastructure, should be incentivised to be in the right place and delivered at the least economic cost.

A key requirement for least-economic cost development of the power system is to have a network pricing regime that is reflective of all system costs imposed by each user of the network, including locational and time-differentiated costs. Network access pricing for least-cost development of the grid should be based on the following principles:

- Fixed costs should be recovered through fixed charges, and variable costs should be recovered through variable charges.
- Cost reflective and forward-looking network tariffs must enable grid users to understand the impact of their use of the network.
- Locational costs should be recovered through locational based charges. If the cost a generator or load imposes on the system depends on the geographical location, such

costs should be recovered through charges that are differentiated by the generator or load's location.

- Costs should be allocated to those who cause them and/or are in the best position to manage them (cost causation principle).

A generator connecting a long distance from demand will require power to be transmitted over a longer distance, which will lead to a greater need for transmission capacity investment and greater costs such as maintenance, operations and refurbishment to be incurred on the transmission network. This network dynamic and cost causation must be reflected in the tariff structures. If the network tariffs are designed to reflect forward looking costs, the investment and operational decisions of both generation and (price responsive - elastic) loads, will reflect the costs they impose on the system for decisions which they have control over, such as where they are located.

The pricing methodology, as described in the Transmission Tariff Code of the South African Grid Code, is already based on a locational use-of-system pricing approach for network capacity and technical losses. The current method is based on a nodal/zonal pricing methodology considering peak load conditions only. This methodology was developed considering a classic power system with large dispatchable bulk generation feeding into the main transmission system and a dominant power flow direction from generation to loads.

The increasing use of variable renewable energies (wind and PV generation) requires a review of the transmission pricing methodology detailed in the current Transmission Tariff Code of the South African Grid Code. The integration of variable renewable energies has changed the fundamental assumptions on which the original methodology was developed, moving from an approach that considers only peak demand to one that needs to include regional power flows.

- Firstly, PV doesn't produce energy during evening peak hours, but still requires additional transmission lines for their peak production during the day which does not coincide with the system peak, shows that a new tariff approach is required, which includes the variability of large amounts of renewable generation.
- Secondly, the generation pattern is gradually evolving, with shifts between fuel sources, and new locations. New generation in export regions, particularly the Cape Coastal areas, contributes to increasing levels of network investments.

The transmission network tariff approach must be evolved to account for a system with more intermittent generation and that different areas of the network face different cost drivers based on the supply and demand in a region. Therefore, regional locational peak system flows, rather than overall peak demand, are better reflections of regional cost drivers and will be more effective at signalling to users the cost of using the Transmission network.

The Grid Code methodology needs to be reviewed and updated to account for this changed and changing power system and to take into account regional peak system flows, rather than overall peak demand as a driver for transmission costs. A forward-looking and locational based tariffs signals should be reviewed regularly to account for the gradually evolving generation mix, with shifts between fuels, and new locations, and future battery connections which will increased demand flexibility.

Against this background:

- Network charges for generators should into account the locational impact of connections on transmission investments and to appropriately reflect the costs and benefits imposed by renewable generation technologies.
- Network charges for loads should be based on a load flow methodology that considers the geographical location as a cost driver for grid infrastructure. The nodal/zonal charging for loads should be aligned to generator charging principles.
- About 3% of total spending on electricity arise because energy is lost in transport over long distances. The charges for energy losses must reflect the regional impacts of generators and loads.
- The locational elements of charging provide some locational signals for the siting of generation and demand. Generators in regions further from demand centres will pay more, and visa-versa.
- Well-designed locational signals will therefore compel generators and loads to consider transmission related costs in their siting decision.

b) Are transmission zones an appropriate mechanism, considering that today energy is injected into the grid from across South Africa?

The zonal methods provide stability and predictability in the transmission use of systems charges and at the same time provides the necessary locational signal to the customers. As more generators connect and inject in the system, the zonal charges also evolve indicating areas that are becoming expensive to connect from and those that are becoming cheaper and thus encouraging customer to relook at their choice of siting the facilities.

Zonal charging for Transmission is therefore appropriate. The charges should be allocated by on the capacity requirement and contribution to peak power flows. Solar PV contributes to peak power flows during the day, whereas other customer categories contribute to peak power flows in the evening.

The requirement for Transmission network capacity is zonally differentiated (solar in Northern Cape, wind in Eastern Cape, coal in Mpumalanga, pump storage primarily in KZN).

c) Distribution tariffs that reflect both the capacity and the distance are being considered. Do you agree with the transmission tariffs that reflect both aspects?

The tariff structure should reflect the cost driver. The cost driver being coincident peak demand and energy losses. Coincident peak demand is also a function on voltage level.

Distribution tariffs should reflect both the capacity charges that is voltage differentiated and a losses charges differentiated by time.

Locational prices for the Distribution network can also benefit both the utility and the customers thereby ensuring efficient usage of the distribution system. However, the distribution networks are generally larger, have more voltage level layers and are more complex than the transmission system. The locational pricing can be considered up to medium voltage level where the large scale generators/plants are likely to connect. Simpler mechanisms should be considered for low voltage networks. The implementation of these location charges will require extensive studies to also evaluate the impact

d) Should municipalities have exclusive right to trade in demarcated municipal boundaries?

NERSA is required to regulate in accordance with the licenses it has granted to various entities. In addition, this is subject to a legal matter before the courts and the outcomes are awaited. NERSA is advised to take direction from the applicable legislation as well as any new developments.