



A CONSULTATION PAPER TO DETERMINE A NEW PRICE DETERMINATION METHODOLOGY

September 2021

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Abbreviations and Acronyms

| | |
|----------------------|---|
| <i>K_d</i> | Cost of debt |
| <i>K_e</i> | Cost of equity |
| ABC | Activity Based Cost |
| β | Beta |
| CAPM | Capital Asset Pricing Model |
| CECA | Capital Expenditure Clearing Account |
| CoS | Cost of Supply |
| CPI | Consumer Price Index |
| CTS | Cost To Serve |
| DMP | Demand Market Participation |
| DMRE | Department of Mineral Resources and Energy |
| DRC | Depreciated Replacement Cost |
| DSLII | Distribution Supply Loss Index |
| dP | Debt Premium |
| E | Expenses |
| EPP | The South African Electricity Supply Industry |
| ERA | Electricity Regulation Act No. 4 of 2006 |
| GWh | Giga Watt hours |
| IPP | Independent Power Producer |
| IRP | Integrated Resource Plan |
| JSE ALSI | Johannesburg Stock Exchange All Share Index |
| LRMC | Long Run Marginal Cost |
| M&V | Measurement and Verification |
| MEAV | Modern Equivalent Asset Value |
| MRP | Market Risk Premium |
| MTSAO | Medium-Term System Adequacy Outlook |
| MWh | Mega Watt hours |
| MYPD | Multi-Year Price Determination |
| NERA | National Energy Regulator Act, No. 40 of 2004 |
| NERSA | National Energy Regulator |
| O&M | Operating and Maintenance |
| OCGT | Open Cycle Gas Turbine |
| PBR | Performance Based Regulation |
| PPA | Power Purchase Agreement |
| RAV | Revaluation Asset Value |
| RCA | Regulatory Clearing Account |
| SSEG | Small Scale Embedded generators |
| TD | Tariff Design |
| TNC | Transmission and Network costs |
| TOC | Trended Original Cost |
| UCT | Unit Capability Factor |
| WACC | Weighted Average Cost of Capital |
| WEPS | Wholesale Electricity Pricing System |

Keywords

Average tariffs

Benchmarking

Consumer tariffs

Data comparisons

Industrial tariffs

Tariff methodologies

Cost of supply methodology

Activity Based Costing

Load profile

Type of use tariff

Marginal Cost based Pricing

Eskom unbundling

Definitions

| | |
|------------------------------|--|
| stable prices | Price stability is a function of predictability, affordability, competitiveness related to the price level (the tariff) and its change over time (price path) |
| demand | Demand is the rate at which electricity is consumed, generally in MW, and informs the capacity required to meet demand at any point in time |
| consumption | Consumption is the total electricity consumed in a given period and generally expressed in c/kWh |
| Tariff Setting Approach | The approach is the framework of principles that collectively are used to determine the fundamentals of the electricity price. Eg. the current approach uses a revenue requirement approach, and the proposed approach will use a combination of principles, namely activity-based costing, type of service and marginal costs to serve. |
| Tariff Setting Methodology | The methodology is the detailed set of steps and modelling required to apply the principles to actually set the tariffs, including the types of data that will be analysed and the format they must be supplied, benchmarks that must be used, indices that will be used (eg. CPI) etc. |
| Retail Utility | Electricity Retailing is the final sale of electricity to the end-user An electric utility is a company in the electricity industry (often a public utility) that engages in electricity generation and distribution of electricity for sale, generally in a regulated market |
| Trading | Trading refers to two types of market participant: <ul style="list-style-type: none"> • Suppliers who physically buy electricity to meet the physical demands of their customers from the generator(s) of their choice • Organisations without a physical demand for electricity, or any means of generating electricity (eg. Banks), to trade electricity. These are known as Non-Physical Traders. |
| Activity-Based Costing (ABC) | Activity-Based Costing (ABC) is as an approach to the costing and monitoring of activities, which involves tracing resource consumption and costing final outputs. Resources are assigned to activities and activities to cost objects. The latter use cost drivers to attach activity costs to outputs. Eg. The price is a function of assigning actual costs to each activity (service) along a value chain, such as generation, transmission, distribution etc. |
| Tariff and price | As per the ERA, both are interchangeable and refer to the charge for electricity |
| Load | This is the demand expressed as the MW required by a consumer at any point in time and often accumulated across consumer categories to develop a load profile that informs the type of electricity source required to meet that load over time |

1 Executive Summary

- 1.1. The current revenue-based methodology has fallen short in providing stable prices. Over the last decade, electricity prices have increased by 175% (despite CPI remaining within a 3 to 7% range), plant availability has plummeted (largely due to unplanned outages) and rolling blackouts (or load shedding) have become the default to manage grid stability when demand exceeds supply. Escalating prices and unreliable supply have constrained economic growth as customers lowered their demand, adopted alternative sources of power, closed down or requested for deviation from the current prices through negotiated pricing agreements (NPAs). Eskom sales have fallen by a significant 14.7% (see Figure 4) – all evidence that basic economic theory and conventional wisdom prevails – as one increases prices, demand falls. To ensure stable (sustainable and predictable) electricity prices, an appropriate new methodology must be developed.
- 1.2. The Multi-Year Price Determination (MYPD) methodology and its embedded Regulatory Clearing Account (RCA) have put the National Energy Regulator of South Africa (NERSA) in an impossible position – approving tariffs that are predicated on allowed costs and sales when the Regulator has no control over the sales. Of the two components of revenue, namely price and sales, the Regulator only has control on price, insofar as it sets the price and effectively ‘guarantees’ the utility a total revenue at that price, however that erroneously assumes that sales will be constant. When sales are not achieved at the ‘guaranteed price’, then the ‘promised’ revenue is also not recovered. NERSA has effectively been making “revenue promises”, when it has no way of “keeping that promise” because it has no control on sales.
- 1.3. Further, utility costs across the entire value chain are lumped together (*averaged*) to determine a total revenue required by the utility that is then used to set an *average* price. Because the individual retail tariffs that are then derived from the *averaged* costs bear no resemblance to the *actual* costs incurred by the utility to deliver a service to individual customer groupings, this has in fact prejudiced customers, especially industrial and manufacturing customers by making them pay for costs they do not contribute to.
- 1.4. Averaging of costs associated with different generators that serve different purposes goes against one of the Section 15(1) tariff principles which states that prices, charges and tariff “*must give end users proper information regarding the costs that their consumption imposes on the licensee’s business.*” The averaging methodology socialises all costs and therefore results in an average price that is (1) too high for some users that need

competitive prices and (2) too low for appropriate alternative energy services. These ambiguous signals trigger negative economic impacts and inappropriate use of electricity for services that ordinarily should be undertaken using alternative energy carriers. Average pricing does not send correct signals to the users.

- 1.5. It is important clarify at this stage that the process to review the price determination methodology was triggered by a comprehensive assessment of the NERSA operating environment. A thorough stakeholder consultation process highlighted the failings of the current MYPD methodology and provided evidence and guidance on the need to overhaul it. The enemy in the current electricity pricing approach is the “averaging”, which results in inefficiencies, cross subsidies and socialisation of costs, which is central in revenue determination. The proposal is effectively aims to eliminate all these. A migration from the revenue-based approach to a cost to serve approach to give effect to the tariff principles in ERA 15(1). Informed by the strategic review, a number of issues and options have been distilled three critical principles, namely:

1.5.1. **Activity Based Costing (ABC)**: Disaggregation of the electricity supply industry into component activities, which are generation (Gx), transmission (Tx), distribution (Dx), system operations (SO), market operations (MO), trading (Td), other ancillary services (AS). This disaggregation forms the backbone of called Activity Based Costing.

1.5.2. **Type of service costing – Differential Load Profiles**: Understanding that energy services are different and may demand different facilities within one or more of the activities defined above, especially at Gx level. These energy services have very different demand profiles which ideally should be supplied with generation plants that have the same or similar supply profiles. The demand profiles, as proxies of energy services, can be broadly categorised into four generic profiles, which are (i) baseload or constant demand, (ii) mid-merit or semi constant demand, (iii) peak or variable demand and (iv) ad-hoc or emergency demand. It is clear that the first 3 types are different but are to a greater extent, predictable whilst the 4th service is by its very nature unpredictable. These services are met by different generation units and different generation units have their inherent different costs derived from the equipment design (a function of the purpose, the technology and related fuel, amongst other costs), and efficiency questions notwithstanding and these should be recognised accordingly. This recognition of the existence of different services which have different cost to serve profiles forms the backbone of the type of service costing.

- 1.5.3. **Marginal pricing to set tariffs:** A few of the activities identified in ABC above and within the type of service, particularly the Gx activity are delivered by a variety of component plants, which as explained in 2 above, have different costs. Focussing on generation, it is clear for that for each type of service, eg. baseload, there are a number of generators, with their different costs and would have been priced accordingly, which could be deployed to provide the service. Baseload plants for instance include coal plants, nuclear plants, imported hydroelectricity, etc. and coal plants are themselves different and have different associated costs. The question is then how is the service priced in recognition of these differently costed plants? The answer lies in the how the market would have dealt with the problem, which is that the cheapest plants in each service bracket, would be deployed first in the order of their cost merit and the costs associated with the last plant that “balances” the market will determine the price for that service. This is the backbone of the marginal pricing.
- 1.6. The three principles above essentially define the proposed price determination system. Clearly there are activities especially in the category “ancillary services” that need to be better understood and costed. The general idea is that the provider of each service will apply for his/her own tariff, individually, by presenting costs associated with his/her own equipment, which costs will include an expected commensurate profit for the provision of the service. Those costs will be converted into an approved tariff for that equipment. In generation therefore, we would expect that each generation facility (ring-fenced properly) will have individually set/approved tariffs. Marginal pricing will deal with the deployment and efficiency issues and the Regulator will not be required to deal with this. Clearly, this requires an independent market and system operator because the idea is to only consider the cheapest plant first and not just deploy one’s plants ahead of more efficient plant.
- 1.7. Clearly, some activities eg. Transmission, Market Operation and System Operation can be combined into a single tariff and others clearly need to be separate e.g. Distribution and Trading. Some ancillary services like market balancing should not be socialised but should be paid for by the parties that are responsible for them but other services like voltage support, frequency moderation and reactive power (which are currently not valued and costed) may need to be socialised and included in the services provided by the Independent Transmission, Systems & Market Operator.
- 1.8. The other key determinants of the proposed system are (i) a need for separation of trading from distribution, (ii) allowing of bilateral contracting, and (iii) the requirement that different services be priced and contracted
-

separately. All other uncontracted service be charged on an emergency basis.

- 1.9. Migration to activity-based costing and service-based pricing approach as well proposed associated regulatory changes bring many benefits to the economy, namely:
 - 1.9.1. Facilitates bilateral contracting, which will potentially-
 - 1.9.1.1. Allows consumers to contract directly with independent power producers (IPPs) of their choice;
 - 1.9.1.2. Releases Eskom from the single buyer status and its obligations;
 - 1.9.1.3. Releases the Fiscus from the contingent liability
 - 1.9.2. Facilitates NERSA to give effect to Section 13(3) of the Electricity Regulation Act, which requires the Regulator to issue separate licences for (a) the operation of generation, transmission and distribution facilities and (b) the import and export of electricity; or trading;
 - 1.9.3. Allows for clear and transparent wheeling and use-of-system tariffs;
 - 1.9.4. Allows for clear determination of cost of generation by different generation plants;
 - 1.9.5. Communicates appropriate cost of generation;
 - 1.9.6. Communicates true IPP costs;
 - 1.9.7. Creates competition amongst different technologies and amongst different market players;
 - 1.9.8. Clearly shows the true cost of provision of a service and therefore provides an appropriate/realistic base for cost reflective tariffs;
 - 1.9.9. Users only pay for their objective costs;
 - 1.9.10. Allows for implementation of the prescripts of Section 15(1) of the ERA;
 - 1.9.11. Prepares South Africa for a fully liberalised electricity industry;
 - 1.9.12. Allowing bilateral contracting allows for ease of funding of these large capital projects;
 - 1.9.13. Potentially eliminates the need for negotiated price agreements;
 - 1.9.14. Will clarify the NERSA mandate beyond electricity deregulation;

2 Introduction

- 2.1 The multi-year price determination (MYPD) is developed as a guide to the Regulator in the regulation of electricity supply industry in a manner that could be deemed rationale and would result in predictable and stable prices. It forms the basis on which the National Energy Regulator (NERSA) will evaluate the price adjustment for Eskom over a multi-year period and becomes the de facto price path. The validity period of the current MYPD4 pricing methodology will be ending on the 31st of March 2022, which implies that a new or revised methodology is required for the ensuing years, the principles of which will inform an interim methodology, which will be used to ensure that all players in the Electricity Industry have appropriate tariffs which are reflective of the costs incurred to deliver required service categories, come the beginning of 2022/23 financial year.
- 2.2 The following strategic objectives have been considered when developing the MYPD5 and associated interim methodology for 2022/23:
- Achieve stable electricity prices for the Electricity Industry
 - Achieve a stable electricity system for the Electricity Industry that supports Eskom's sustainability
 - Improved systems and tools
- 2.3 Adherence to key principles will be necessary to achieve the following objectives:
- Activity Based Costing (ABC): A migration from the revenue-based approach to an activity-based costing approach, where different activities are disaggregated along the value chain
 - Differentiated Load Profiles: With the ABC disaggregation of the value chain into discrete activities, it was necessary to reflect the reality of how the cost to serve are further disaggregated according to the load profile for different categories of consumer,
 - Marginal Price Tariffs: Within each of the load profiles, and related costs to serve, the pricing must reflect the market realities – least cost available supply is dispatched first to meet the load as it builds from base through mid-merit and peak load.

The principles above will be comprehensively assessed in paragraphs 5, 6 and 7 respectively.

3 Legal Basis for the Pricing Review

- 3.1 The development of the methodology is a process positioned on achieving fair evaluation, efficient and effective administrative process and achievement of rationality from a marsh of information. The general nature of the powers mandated to NERSA by section 4 of the Electricity Regulation

Act, 2006 shall without related regulatory instrument results in abstract conclusions.

- 3.2 The methodology, as developed, does not enjoy the status of the law or binding on courts. The methodology derives its binding nature when applied to a decision-making process. Once it is dedicated to application on particular process, NERSA cannot arbitrarily deviate from it without considering due process. The discretion for its usage is because NERSA is vested with the powers to determine electricity price/tariff.
- 3.3 Clause 6.2 of Eskom's distribution licence carries a condition imposed by NERSA referencing the usage of a methodology to determine prices and tariffs. The powers to determine such condition is derived from section 14(1)(e) of the ERA. The development of the methodology is to satisfy the condition set for purposes regulating Eskom prices and tariffs.
- 3.4 There are other hosts of conditions issued to Eskom related to approval of prices and tariffs. These conditions are an enhancement of section 15(2) which generates statutory prohibition on the part of the licensee. It is therefore fundamental to detail that, section 15(1) of the ERA is predicated on what has been expanded in clause 3.3 above.
- 3.5 The methodology which is the product of the conditions which section 15(1) is established on, should enable the decision making on tariffs, charges and tariffs and regulation of revenue to achieve what is listed in (a) – (e).
- 3.6 In a nutshell, section 15(1) finds its place for implementation on the licence condition issued, this provision creates an extended framework on the consideration of revenue, tariff and charges. The parameters detailed in the section cannot be ignored when considering tariffs, revenue and charges as the law has prescribed them.

4 Shortcoming of the current methodology – the case for review

- 4.1 **Stakeholder rejection of the current Price Instability:** Stakeholder comments during the public consultation process highlighted that certain sections of the Methodology did not adequately address some of the intended objectives, namely to provide price stability. Various commentators and experts have pointed to various aspects of the current MYPD methodology as flawed; however, a thorough assessment suggests that it is the entire pricing approach that is flawed and needs to be replaced. Questions were raised about the asymmetry of information and challenges in verifying the prudence of costs incurred to determine the revenue requirement. Business associations consulted, indicated that the current

revenue-based approach has not delivered the intended predictability of the MYPD over the long term.

- 4.2 **Policy shifts nudging the Industry towards deregulation:** Further to these stakeholder concerns, it was announced that Eskom will be unbundled, structurally transforming the electricity industry – phasing out the single buyer modality, replacing it with an independent system operator and potential increase in bilateral contracts. In addition, the threshold for unlicensed registration of generators up to 100MW coupled with bilateral contracting and eased access to the grid coupled with stable wheeling tariffs, all point to the urgent need to overhaul the pricing methodology amongst other elements of the regulatory framework.
- 4.3 **Transformation of the Electricity Industry and the unbundling of Eskom:** In the reformed electricity market, the transmission systems operator will have to act as an unbiased electricity market broker, to promote capital investment within the electricity demand and supply industry and to catalyse energy efficiency and sustainability. Unbundling also allows for the ISO to independently contract with independent power producers and Eskom generation without the conflict of interest, as it currently exists.¹ In wholesale markets the majority of power is bought through bilateral contracts and the remaining power through spot markets which acts as clearing house for buyers and sellers.
- 4.4 As it can be observed in Figure 1 and Figure 2 the electricity market model can be viewed in different ways. In Figure 2, there are alternatives to the Eskom view of the deregulated electricity system, that give expression to the ambitions of traders and generators who wish to bilaterally contract with end users - either directly with onsite supply or wheeled over the grid.

¹ UCT GSP Power Futures Lab,
https://static1.squarespace.com/static/5c1364db45776e7d434895a3/t/5cba0cf9e4966b8949b48e4c/1555696893795/Unbundling+Note_April2019.pdf

Figure 1: Eskom’s proposed interim electricity market²

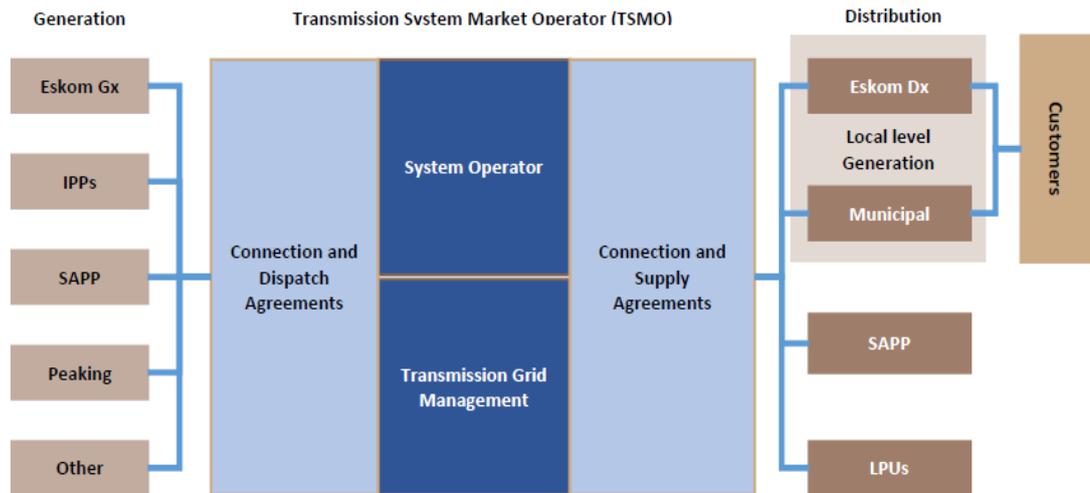
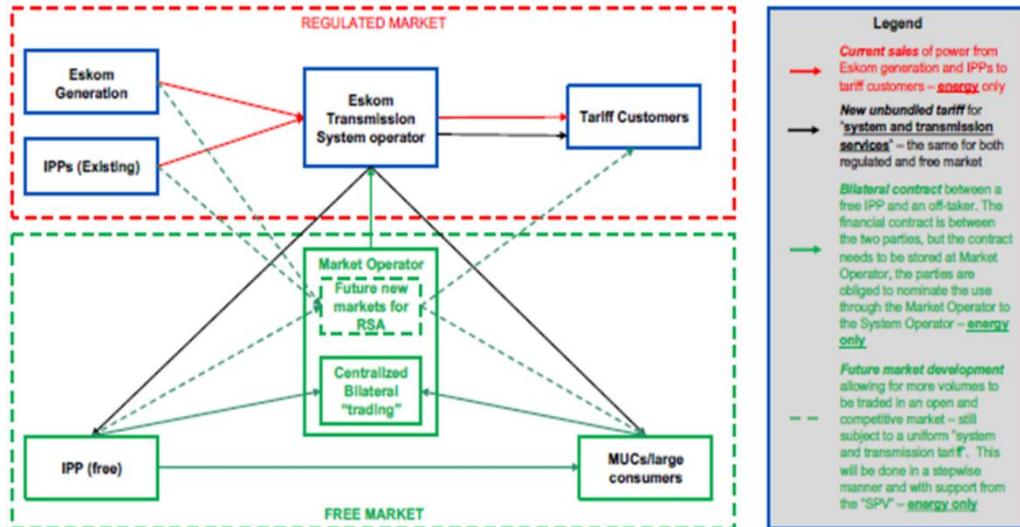


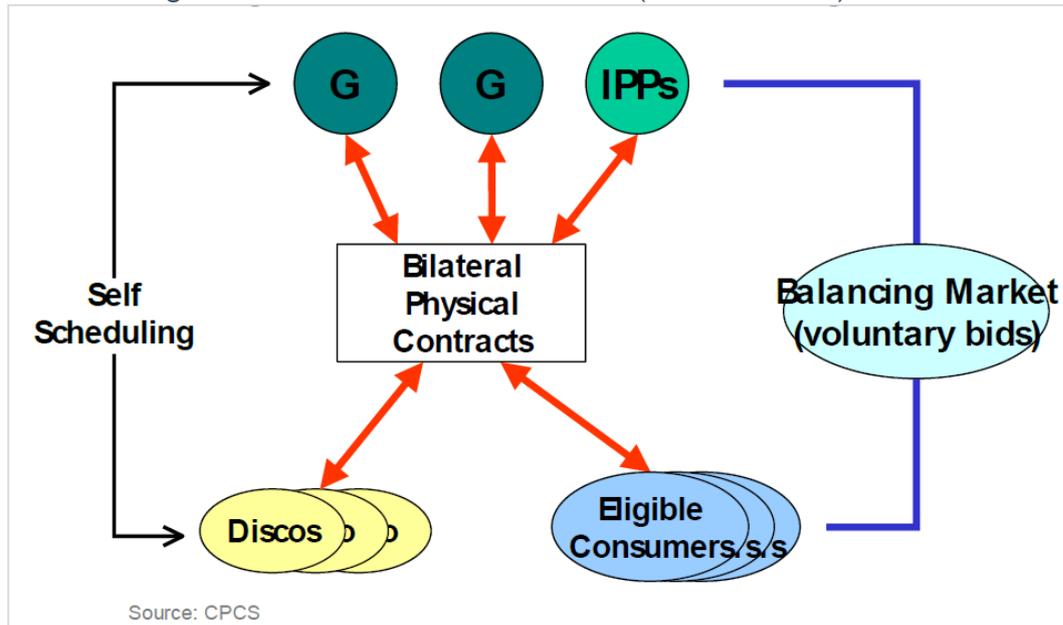
Figure 2: Simplified model of an alternative electricity market structure
 This focuses on the trading arrangements



4.5 The above market structure (Figure 1) is very much seen through the Eskom lens whereas as alternatives may introduce more choice and voluntary market participation thus reducing Eskom’s dominance and introducing competition and consumer choice, as outline in Figure 3, which represents the European market model, also found in India and other Asian countries. NERSA will explore the most appropriate structure and will express its view after concluding the consultation process.

² Department of public enterprises: https://www.gov.za/sites/default/files/gcis_document/201910/roadmap-eskom.pdf

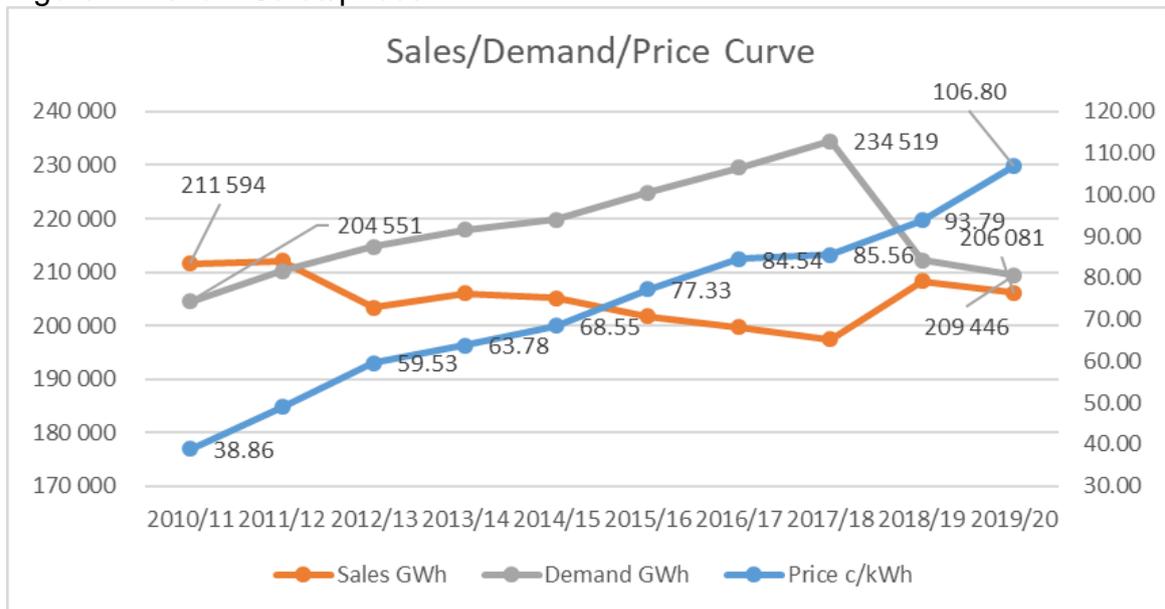
Figure 3: Bilateral contracts Model (multi markets)



- 4.6 In this reformed market, prices are designed according to the principle that in order to achieve efficient allocation of resources, the market price should be determined by marginal cost of production. In these markets, where there are number of generators, the ranking of bids will ensure that units with lower costs to serve are dispatched first to meet the load profile of the market and that the market prices are equal to the industry wide marginal costs of production to meet the load types that characterise the market load profile.
- 4.7 **Transforming Electricity Industry:** South Africa's electricity sector is transforming at a rapid rate, often driven by issues beyond NERSA's control but often within NERSA's influence. Energy security concerns, rising electricity prices, the increase in renewable energy generation and small-scale embedded generators are major contributors to the energy transformation. In light of these dynamics, licensees including municipalities need a pricing model that compensates for efficient performance, promotes efficient investments and provides multiyear predictability.
- 4.8 **Pricing Electricity for System Stability:** High penetration of unregulated variable energy sources will probably result in the oversupply during off peak periods and serious undersupply during morning and early evening peak periods before the sun rises or as the sun sets. An appropriate pricing approach will reflect the costs associated with electricity required to meet the residual demand during morning and early evening without overburdening those consumers that are not causes of these great variations in demand and prices. This great variability during high demand peak periods will likely rise dramatically but there will be a demand for decent prices.

4.9 Rising Prices, Falling Sales – Utility Death Spiral? The current methodology is based on determining the average price by dividing allowed revenues, largely determined by generator’s declared costs, with the forecasted sales. This approach means that Eskom’s declared costs have been increasing, triggering applications for increased revenues. The corresponding increasing prices are contrasted with sales that have been declining over time, as shown in Figure 4 below. Eskom sales in 2010 were 211 594GWh and 206 572GWh in 2019/20. The wholesale price increased from 38.86c/kWh to 106.90c/kWh over the same period, an increase of 175%.

Figure 4: Eskom Sales/prices



4.10 Basic economic infrastructure failing economic development: The impact of the falling sales against escalating prices does not tell the whole story. One needs to identify where the sales have been forfeited to understand the lose-lose impact for South Africa. As outlined in Table 1, Eskom has forfeited most of its sales from critical economic sectors, namely productive primary sectors producing the feedstock for industrial/manufacturing sectors benefiting our natural resources. Whether these be mining companies producing minerals or agri-processing³ companies using our agricultural resources, South Africa’s greatest sources of tradables are derived from the minerals, agricultural and tourism sectors. Likewise, the fall in rail sales suggest, that as a proxy for industrial activity, the drop in transport of manufactured goods is a knock-on effect of the decline in production and subsequent decline in electricity sales.

³ Agri-processing industry is a subset of manufacturing that processes raw materials and intermediate products derived from the agricultural sector.

Table 1: Eskom Sales by sector (2012 - 2021)

| Electricity sales per customer category, GWh | 2021 | 2020 | 2019 | 2018 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | (Reduction)/growth in GWh sales, % |
|--|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|------------------------------------|
| Distributors | 82 446 | 85 984 | 87 236 | 87 133 | 89 718 | 89 591 | 91 090 | 91 262 | 91 386 | 92 140 | -10.5% |
| Residential | 10 949 | 11 293 | 11 748 | 12 302 | 11 863 | 11 917 | 11 586 | 11 017 | 10 390 | 10 522 | 4.1% |
| Commercial | 9 696 | 10 486 | 10 558 | 10 539 | 10 339 | 10 150 | 9 644 | 9 605 | 9 519 | 9 270 | 4.6% |
| Industrial | 40 881 | 45 610 | 48 717 | 47 854 | 48 295 | 50 150 | 53 467 | 54 658 | 51 675 | 58 632 | -30.3% |
| Mining | 26 991 | 28 703 | 28 972 | 30 235 | 30 559 | 30 629 | 29 988 | 30 667 | 31 611 | 32 617 | -17.2% |
| Agricultural | 5 461 | 5 770 | 5 796 | 5 711 | 5 405 | 5 733 | 5 401 | 5 191 | 5 193 | 5 139 | 6.3% |
| Rail | 1 931 | 2 600 | 2 831 | 3 148 | 2 849 | 2 852 | 3 098 | 3 125 | 2 996 | 3 270 | -40.9% |
| International | 13 497 | 15 189 | 12 461 | 15 268 | 15 093 | 13 465 | 12 000 | 12 378 | 13 791 | 13 195 | 2.3% |
| TOTAL | 191 852 | 205 635 | 208 319 | 212 190 | 214 121 | 214 487 | 216 274 | 217 903 | 216 561 | 224 785 | -14.7% |

4.11 **Consumers paying the price for lost sales:** The variance between actual and forecasted sales has led to a number of RCA applications over the period for increased revenue to cover lost sales – a fundamental flaw in the current revenue methodology that ruins efforts to provide price stability. In the current methodology, NERSA has no ability to hold the licensees accountable for lower sales as NERSA is not empowered to instruct Eskom how to run its business. An approach needs to be found that sets prices and makes it the licensee's responsibility to manage its sales at regulated and benchmarked prices.

4.12 **Weak price signals drive poor consumer choices:** The current tariff setting methodology and the approach of averaging costs, determining revenue and translating them into prices, have distorted prices and dampened the behavioural responses. Different demand profiles require different supply options, which come from different types of generators, ranging from baseload plants, through variable energy sources to various energy storage technologies. Different generation technologies have different costs, not because of inefficiency but because of their design. Plants that have high spinning reserve capacity present a very different cost profile to other plants and they play a unique role in stabilising the system and require appropriate pricing approach. Emergency or back-up power, for instance, cannot be priced the same way as normal run-of mill power generation.

4.13 **The law demands cost to serve approach:** Averaging of all the costs associated with different generators that serve different purposes goes

against one of the tariff principles which states that prices, charges and tariff “*must give end users proper information regarding the costs that their consumption imposes on the licensee’s business.*” The averaging methodology socialises all costs and therefore results in an average price that is 1) too high for some users that need competitive prices and 2) too low for competitive substitutions and therefore results negative economic impacts and inappropriate use of electricity for services that ordinarily should be undertaken using alternative energy carriers. Average pricing does not send correct signals to investors and users alike. In short, in the context of a deregulating market, average pricing does not incentivise competition, by contrast it dilutes competition, entrenching dominant incumbents.

4.14 Issues driving Electricity Industry transformation: In the context of these fundamental issues transforming the Electricity Industry and related shortcomings in the current revenue based MYPD methodology, and changing environment, the rationale for this impending overhaul, is drawn from a number of issues that need correcting, including inter alia:

- 4.14.1 the incompatibility of allowable revenue to the current regulatory environment and a transition to a transparent cost reflective approach;
- 4.14.2 minimising the impact of declining sales on consumers and correctly transferring the sales risk back to the producers;
- 4.14.3 minimising the impact of poor performance on consumers whilst correctly locating the incentive to improve efficiency with the producers; and
- 4.14.4 misalignment between PPAs and the dispatch rules by using market related mechanisms to correct such misalignment
- 4.14.5 unbundling of the Electricity Industry and calls to facilitate market access
- 4.14.6 need to facilitate bilateral contracts within clear and equitable market rules that limit abuse of natural monopoly power
- 4.14.7 development of fair and robust rules that replace the role of Eskom’s system operator and Eskom being a single buyer
- 4.14.8 dequirement for predictable clear wheeling tariffs

Stakeholder Question 1:

Stakeholders are requested to comment on the following:

- a) The transformation of the Electricity Industry and its implications from the stakeholder’s perspective, especially:
 - a. what is driving change; and
 - b. their expectations from the transformation.

- b) What are your views on electricity market structure, and what would be the alternative structure?
- c) The reasonableness of calculating average price based on the forecast sales.
- d) The fairness of allowing licensees to claw back lost sales through increased tariffs for consumers.
- e) What alternative approaches to determine prices should be considered, that:
 - a. are not dependent on licensee forecasted sales; and
 - b. make the licensee carry the sales risk and not consumers

5 Activity Based Costing (ABC):

- 5.1 It is a migration from the revenue-based approach to an activity-based costing approach to derive cost reflective tariffs to give effect to the tariff principles in section 15(1) of the ERA – underpinning the cost to serve. This involves the disaggregation of the electricity supply industry into component activities, which are generation (Gx), transmission (Tx), distribution (Dx), system operations (SO), market operations (MO), trading (Td), other ancillary services (AS). This disaggregation forms the backbone of the Activity Based Costing approach.
- 5.2 Activity-based costing is a modern regulatory approach, which identifies specific cost drivers and then allocates costs based on the details of the utility's equipment, operation, and product mix. This approach is a management costing method that allocates overhead and indirect costs to related products and services. It recognizes the relationship between costs, overhead activities, and products. Traditional tariff setting methodologies differs from ABC because they are based on aggregation of costs to calculate an opaque average cost.
- 5.3 Activity-based costing does not only identify the accurate cost of each product but is a decision-making tool to determine if the cost allocated is prudent and efficient. Data needs to be accurate, without correct information, it is impossible for the Energy Regulator and utilities to make accurate decisions. This approach is a tool that can assist utilities to be more efficient and thereby be more profitable and assist regulators to make pricing decisions that reward prudence and efficiency but more importantly prices that are cost reflective.
- 5.4 By using activity-based costing, utilities will be incentivised to:
 - 5.4.1 allocate relevant costs to relevant services and thereby understand their business activities' cost drivers;
 - 5.4.2 recognise that electricity requires different costs throughout its value chain;
 - 5.4.3 accurately set their electricity prices; and
 - 5.4.4 identify costs that may be cut to achieve efficiency.

Stakeholder Question 2:

Stakeholders are requested to comment on the following:

- a) Use of activity-based costing for regulatory price setting.
- b) The implementation of the ABC approach in the SA Electricity Industry within:
 - a. the current electricity industry structure; and
 - b. a future disaggregated Electricity Industry.

- 5.5 In order to establish a transparent ABC approach, NERSA will need a comprehensive understanding of the market from the demand side and supply side. In this model all Gx, Tx, Dx and retail costs are disaggregated CAPEX and Opex costs associated with a specific load. The model requires certain inputs, which are discussed below.
- 5.6 **Demand analysis data:** Demand information gathering on all customer consumption - domestic, industrial, commercial and manufacturing. The information needs to be provided on an hourly basis. The information will also assist in the analysis of the base load, mid-merit/intermediate and peak consumption for each customer category.
- 5.7 Licensees and consumers will be required to provide information on demand profile customer categories per hour in a format determined by NERSA (noting that a large amount of information will be sourced through comprehensive energy surveys of both producers and consumers), however, an indicative format is provided below:

Table 2: Indicative demand data collection format

| Time | EIUs | industrial | pumped storage | manufacturing | commercial | households |
|----------|-------|------------|----------------|---------------|------------|------------|
| 00:00:00 | 15000 | 4000 | 2700 | 500 | 100 | 100 |
| 01:00:00 | 15000 | 5000 | 2700 | 500 | 100 | 50 |
| 02:00:00 | 15500 | 4000 | 2700 | 500 | 100 | 50 |
| 03:00:00 | 15000 | 4000 | 2700 | 500 | 100 | 50 |
| 04:00:00 | 15500 | 5000 | 1700 | 700 | 100 | 50 |
| 05:00:00 | 15000 | 6000 | 1400 | 800 | 300 | 300 |
| 06:00:00 | 15000 | 6000 | 1200 | 1000 | 400 | 500 |
| 07:00:00 | 15500 | 6000 | 0 | 2000 | 600 | 1500 |
| 08:00:00 | 16500 | 6000 | 0 | 2000 | 1500 | 2500 |
| 09:00:00 | 16500 | 6000 | 0 | 2000 | 1500 | 3500 |
| 10:00:00 | 16000 | 6000 | 0 | 2000 | 1500 | 3000 |
| 11:00:00 | 16000 | 6000 | 0 | 2000 | 1500 | 1500 |
| 12:00:00 | 15500 | 6000 | 0 | 2000 | 1500 | 1000 |
| 13:00:00 | 15500 | 6000 | 0 | 2000 | 1500 | 1000 |
| 14:00:00 | 16000 | 6000 | 0 | 2000 | 1500 | 1000 |
| 15:00:00 | 16000 | 6000 | 0 | 2000 | 1500 | 1500 |
| 16:00:00 | 16000 | 6000 | 0 | 2000 | 1500 | 2500 |
| 17:00:00 | 15500 | 6000 | 0 | 2000 | 2000 | 3500 |
| 18:00:00 | 16000 | 6000 | 0 | 2000 | 2500 | 4000 |
| 19:00:00 | 16000 | 5000 | 0 | 1500 | 3000 | 4500 |
| 20:00:00 | 15500 | 5000 | 0 | 1500 | 3000 | 3000 |
| 21:00:00 | 16000 | 4500 | 0 | 1000 | 2000 | 2000 |
| 22:00:00 | 16000 | 5000 | 1000 | 800 | 1000 | 1000 |
| 23:00:00 | 16000 | 4000 | 1800 | 600 | 500 | 500 |

Stakeholder Question 3:

- a) Stakeholders are requested to comment on the format to collect the demand analysis information.
- b) Is this proposed information adequate to achieve activity-based costing regulation? If not, what are other alternative types of information.

5.8 Costs of Equipment

5.8.1 NERSA (2016) states, 'The cost of supply framework states that functionalised costs are classified as either fixed or variable costs. Next, fixed and variable costs are classified as demand, usage or energy and customer-related'. The sum of these three types of costs within a given class is the cost to serve that class. Fixed costs are costs that remain constant regardless of the volume of output and are predominately associated with capital investment in infrastructure. Variable costs are costs that vary with the volume of output. For municipalities whose wholesale price is derived from the generation cost of production, this is predominantly the embedded fuel cost.

- 5.8.2 Equipment contributes a bigger portion of costs in the provision of electricity, and licensees will be allowed to recover the prudently incurred costs for a sustainable electricity supply. However, licensees need to demonstrate to NERSA that costs associated with the equipment used in the provision of electricity were necessary and prudent to meet the needs of the Electricity Industry referenced in section 2 above, as provided by an efficient licensee referenced in section 15 of the ERA.

5.9 Generation Costs

- 5.9.1 The cost of generating electricity need to be expressed in terms of a unit cost per kWh delivered from the power station. These costs will include capital cost to generate power and equipment used; the cost of fuel burned; and the cost of operating and maintaining the power station or plant.
- 5.9.2 Each technology in the generation business has its own set of characteristics that are valued based on their purpose and related activities. The generation mix of licensees should not be determined solely by their cost, but a rigorous understanding of those costs that will assist the market in attaining the true cost of supply.
- 5.9.3 Equipment must include assets that are used and/or usable to provide regulated service by licensees. The equipment will consist of generation, transmission and distribution assets. Licensees will be required to categorise information provided under generation costs according to a format determined by NERSA (noting that a large amount of information will be sourced through comprehensive energy surveys of both producers and consumers), however, an indicative format is provided below. This information will be required for each applicable plant, for instance coal, nuclear, wind, solar photovoltaic (PV), concentrated solar power (CSP), pumped hydro, battery storage and imported hydro.

Table 3: Indicative equipment cost data collection format

| Load factors | Applicable plant | Typical Capacity | Capital costs | Ops & Maint costs | Life of plant | Depreciation |
|--------------|------------------|------------------|---------------|-------------------|---------------|--------------|
| 5% | OCGT | | | | | |
| 10% | OCGT | | | | | |
| 15% | OCGT | | | | | |
| 20% | OCGT | | | | | |
| 30% | OCGT | | | | | |
| 40% | OCGT | | | | | |
| 50% | OCGT | | | | | |
| 60% | OCGT | | | | | |
| 70% | OCGT | | | | | |
| 90% | OCGT | | | | | |
| 99% | OCGT | | | | | |

Stakeholder Question 4:

- a) Is this information adequate to achieve activity-based costing regulation? If not, please provide an alternative
- b) What would be an appropriate tariff cost build-up for a generation business to make a return on its investment?
- c) Stakeholder are requested to comment on the appropriateness of the approach proposed by NERSA to set the generation component of the price of electricity.
- d) Which international benchmarks and best practices should NERSA consider – both in terms of type and sources.
- e) How should NERSA ensure that only efficient costs from the distribution utilities are recovered?
- f) Is the list of costs identified by the Energy Regulator sufficient, if not suggest the other relevant costs?

5.10 Transmission, System & Market operation Costs

5.10.1 The ISO is completely responsible for provision of a reliable electricity service to market participants. To ensure continued provision of reliable service at the transmission level NERSA requires unbundled costs. The benefits that a transmission line contributes to the various role players in the system need to be measured. The aggregate benefits that accrue to all of the transmission system users should be higher than the fixed cost otherwise such assets would not be efficient.

5.10.2 According to Arellano M.S. and Serra P, (2004) regarding the electricity transmission pricing principles, the pricing system applied to transmission should be related to the pricing system used to pay for energy and capacity. The Energy Regulator requires information on load factors, power transmitted, transmission, system and market operation costs. The

network capacity costs will essentially also form the wheeling tariffs across transmission networks where appropriate. The power elements will be separated out and form a large part of trading tariffs as the market matures.

5.10.3 The cost of interconnecting a new generator, or power plant, with the transmission grid consists of costs for the spur transmission line that connects the generator to the existing bulk transmission system, the point of interconnection (POI) that facilitates the flow of power between the spur line and the bulk system, and any required upgrades to the bulk transmission system itself. The generator developer pays for the spur line and point of interconnection, but bulk system upgrade costs are recovered directly from end-use customers via an added to retail bills, Carley et al. (2018)

5.10.4 To enable the Regulator to perform its roles transmission license holders are required to provide information in the format determined by the Regulator (noting that much of the information will be sourced through comprehensive energy surveys of both producers and consumers) an indicative format is provided below:

Table 4: Indicative transmission cost data collection format

| Load factor | Power transmitted (MW) <500V | Transmission costs | System operation costs | Market operation costs |
|-------------|------------------------------|--------------------|------------------------|------------------------|
| 5% | | | | |
| 10% | | | | |
| 15% | | | | |
| 20% | | | | |
| 30% | | | | |
| 40% | | | | |
| 50% | | | | |
| 60% | | | | |
| 70% | | | | |
| 90% | | | | |
| 99% | | | | |

Stakeholder Question 5:

- a) Is this information adequate to achieve activity-based costing regulation? If not, please provide an alternative.
- b) What would be an appropriate tariff cost build-up for a transmission business to make a return on its investment?
- c) Stakeholders are requested to comment on the appropriateness of the approach proposed by NERSA to set the transmission component of the price of electricity.
- d) Which international benchmarks and best practices should NERSA consider – both in terms of type and sources?
- e) How should NERSA ensure that only efficient costs from the transmission utilities are recovered?
- f) Is the list of costs identified by NERSA sufficient? If not, suggest the other relevant costs.

5.11 Distribution equipment costs

5.11.1 Electricity distribution licensed operator, operate networks with different shapes, which directly affect the costs. Electricity distribution process consist primarily of labour, capital and the power purchased from the generator. These costs can be further subdivided into two main parts: which the costs of the purchased power and the network costs including labour and capital costs. In measuring cost efficiency in licensed distribution utilities, the energy regulator adopted a total costs approach and network costs approach. The network costs will essentially also form the wheeling tariffs across municipal networks where appropriate. The power elements will be separated out and form a large part of trading tariffs as the market matures.

5.11.2 Therefore, NERSA requires information relation to the load factor; power distributed and wires costs to be able to set the tariffs for distribution-licensed utilities.

Table 5: Indicative distribution cost data collection format

| Load factor | Power distributed (MW) - S1 | Wires costs |
|-------------|-----------------------------|-------------|
| 5% | | |
| 10% | | |
| 15% | | |
| 20% | | |
| 30% | | |
| 40% | | |
| 50% | | |
| 60% | | |
| 70% | | |
| 90% | | |
| 99% | | |

Stakeholder Question 6:

- a) Is this information adequate to achieve activity-based costing regulation? If not, please provide an alternative.
- b) What would be an appropriate tariff cost build-up for a distribution business to make a return on its investment?
- c) Stakeholders are requested to comment on the appropriateness of the approach proposed by NERSA to set the distribution component of the price of electricity.
- d) Which international benchmarks and best practices should NERSA consider – both in terms of type and sources?
- e) How should NERSA ensure that only efficient costs from the distribution utilities are recovered?
- f) Is the list of costs identified by NERSA sufficient? If not, suggest the other relevant costs.

5.12 Trading Costs

5.12.1 Electricity like most bulk products is first produced and the sold at the wholesale price level before it is sold and distributed to consumers at the retail level. The costs of electricity at retail level are mainly customer focused and are service and administrative costs. In South Africa electricity is brought to customers through contracts between generators, transmitters and distributors. In a transformed Electricity Industry, there are indications that bilateral contracts will play a greater role, especially where transparent costs to serve enable consumers to sign contracts with least cost suppliers where appropriate and so forth.

5.12.2 Where applicable, the wholesale price would be the factory gate price with transmission, but for each type of load there will be a baseload wholesale price and the system used to distribute electricity. The largest portion of the wholesale costs is the energy price and these costs need to be recovered from customers. The customer's retail bill will include the wholesale market price appropriate to each load profile for the appropriate category of customer.

Stakeholder Question 7:

- a) What are the cost elements at the trading level of electricity value chain?
- b) The pricing approach intends to separate out the 'wires' business of electricity supply (transmission/distribution) from the 'transactions' business of trading – is this realistic in the current market? Please substantiate your answer.
- c) How should the NERSA ensure that the costs at trading level are efficiently recovered?

5.13 Retailing Costs

5.13.1 Electricity retailing is the last step in the value chain of electricity supply; it is the sale of electricity from generation to each category of end-use consumer. It is the fourth major step in the electricity supply chain. The price determination includes the customer's load profile and conditions, as well as marketing costs. The electricity distributor also has a role of collecting and controlling consumer data.

5.13.2 The following costs are required for Energy Regulator for to set an appropriate tariff for retail business:

- Billing costs relating to computer charges (software and hardware);
- Costs relating to the processing of bills;
- Customer service/support costs;
- Metering costs;
- Maintenance of meters.

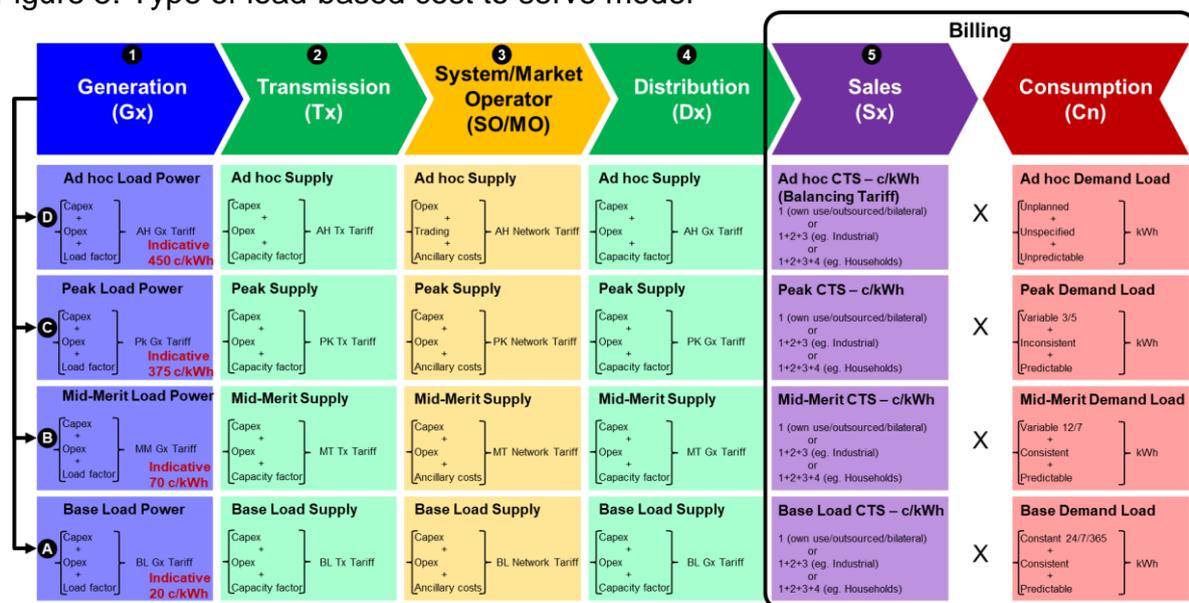
Stakeholder Question 8:

- a) Comment of the costs list required from retail business
- b) How could the price of retail business be best set?

6 Type of Service Costing – Differentiated Load Profiles

- 6.1 With the disaggregation of the value chain into discreet activities, it was necessary to reflect the reality of how the cost to serve are further disaggregated according to the load profile for different categories of consumer – base load, mid-merit/intermediate load, peak load and emergency load. The characteristics of each load drive the costs to serve each consumer category, in terms of the technology and fuel, amongst other costs,
- 6.2 Understanding that energy services are different and that there are different demand facilities within one or more of the activities defined above, especially at Gx level. These energy services have very different demand profiles, which ideally should be supplied by generation plants that have the same or similar supply profiles. The demand profiles, as proxies of energy services, can be broadly categorised into four generic profiles, which are (i) baseload or constant demand, (ii) mid-merit or semi constant demand, (iii) peak or variable demand and (iv) ad-hoc or emergency demand.
- 6.3 It is clear that the first three types are different but are, to a greater extent, predictable while the 4th demand is by its very nature unpredictable. These demands are met by different generation units and different generation units have their inherent different tariffs costs and efficiency, and these should be recognised accordingly. This recognition of the existence of different services which have different cost to serve profiles forms the backbone of the **type of service costing**.

Figure 5: Type of load-based cost to serve model



- 6.4 Different demand profiles require different supply options, which come from different types of generators, ranging from baseload plants, through variable energy sources to various energy storage technologies. Different generation technologies have different costs, largely driven by design – determined by purpose, technology and fuel. Plants that have high spinning reserve capacity present a very different cost profile to other plants, and they play a unique role in stabilising the system and require an appropriate pricing approach. Emergency or back-up power, for instance, cannot be priced the same way as normal run-of mill power generation.

Stakeholder question 9:

Stakeholders are invited to comment on whether:

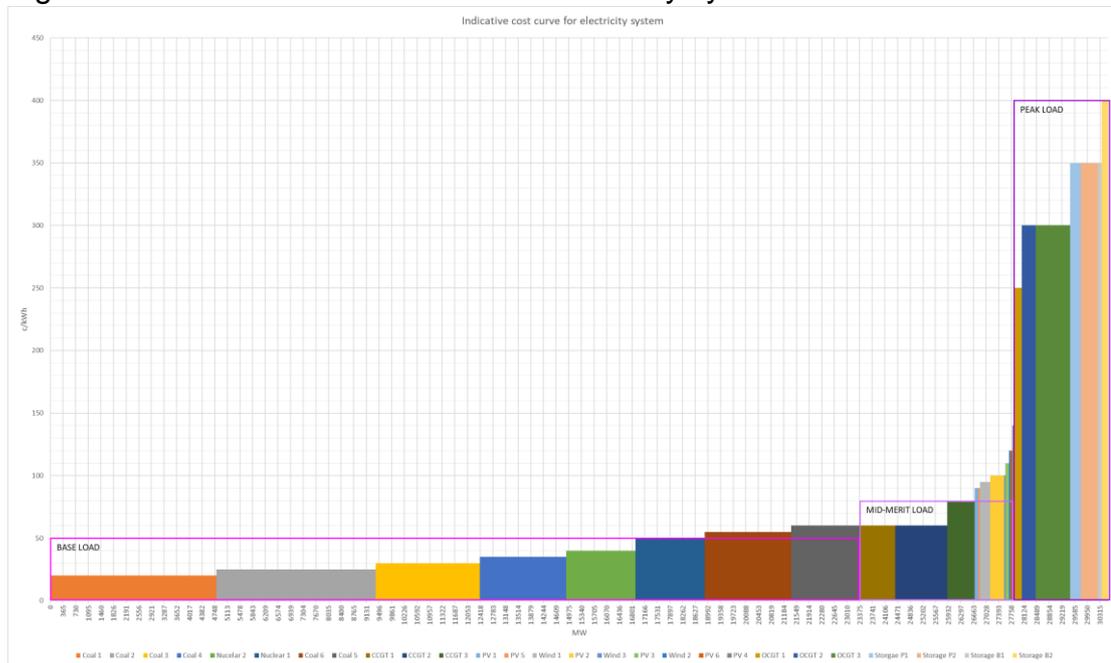
- a) the proposed approach addresses the concern raised about the current pricing approach detailed in sections 4 and 5 above;
- b) the proposed model achieves efficient economic allocation of resources used to supply electricity;
- c) the proposed approach will encourage efficient investment into the sector; and Whether the model caters for the unbundled electricity sector with an ISO.

7 Marginal Price Tariffs:

- 7.1 A few of the activities identified in activity-based costing and within the type of service, particularly the Gx activity, are delivered by a variety of component plants, which have different costs, as explained in the type of service in section 6 above. Focussing on generation, it is clear that for each type service, e.g. baseload, there are a number of generators, with their different costs and would have been priced accordingly, which could be deployed to provide the service. Baseload plants include coal plants, nuclear plants and imported hydroelectricity. Coal plants are themselves different and have different associated costs. The question is then how is the service priced in recognition of these differently costed plants? The answer lies on how the market would have dealt with the problem, which is that the cheapest plants in each service bracket would be deployed first in the order of their cost merit upwards along the supply curve, as depicted in Figure 6, and the marginal costs associated with the last plant that ‘balances’ the market will determine the marginal price for that service. This is the backbone of the **marginal pricing**.
- 7.2 Marginal cost study analyses how the system is planned and operated in order to determine how costs would change if there were a small increase (or decrease) in energy used in a given period, in load in critical hours, in number of customers of a particular type, etc. The main advantages of marginal cost pricing are that prices signal the economic costs of

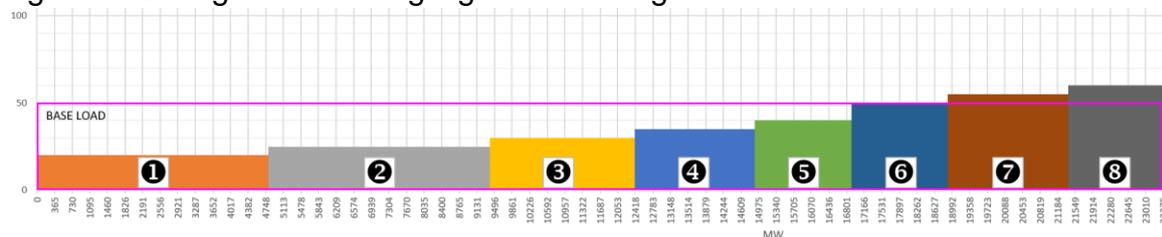
consumption and investment decisions, and that regulated tariffs mimic the cost structures faced by competitive supplier.

Figure 6: Cost Curve for an indicative electricity system



7.3 As depicted in Figure 6 above depicts; as the demand increases, the cost of generation increases with the technology used. This includes the costs of ramping up production to meet peak demand. This approach is adopted in wholesaler markets where the market determines which sources of electricity will be used to meet demand by dispatching the cheapest sources available at any time. Low-cost dispatch loads are dispatched first followed by higher cost sources according to need. The marginal cost or incremental cost is based on the technology and associated fuel burned to produce each kilowatt hour of electricity. In highly competitive markets the dispatch is not determined by a systems operator but through bid pricing.⁴

Figure 7: Enlarged view to highlight baseload generators



7.3.1 In Figure 7 the width of each column equates to the relative proportion of power supplied (MW) and the height is the cost (c/MWh), and the power suppliers are:

| | | | |
|-----------|-----------|-----------|-----------|
| 1. Coal 1 | 2. Coal 2 | 3. Coal 3 | 4. Coal 4 |
|-----------|-----------|-----------|-----------|

⁴ Cain CC, Lesser J, 2007, A common sense guide to the wholesale market.

| | | | |
|--------------|--------------|-----------|-----------|
| 5. Nuclear 2 | 6. Nuclear 1 | 7. Coal 6 | 8. Coal 5 |
|--------------|--------------|-----------|-----------|

- 7.3.2 While the cost curve is indicative, it is made up of realistic costs to serve and one can see that generators 7 and 8 are the most expensive, and generator 6 will set the marginal price for baseload power – over time. Generators 7 and 8 will eventually close down as the market will not generate sufficient revenue as they will have limited calls on their power. However, another investor who believes they can install new baseload capacity and provide power at less than the marginal price, will be able to make informed choices about the plant size and technology as they will replace at least one if not two plants.
- 7.3.3 The current energy prices are based on the time-of-use (TOU) approach, which seeks to send signals for customers to shift their consumption to certain periods of the day where the demand for electricity is low. The current ratio for peak to off-peak consumption is 1:8, which means its eight times more expensive to consume electricity during winter peak periods as opposed to low season off-peak periods as depicted below – regardless of what the cost to serve might be, it does not cost more to generate electricity from the same plant in summer or winter.
- 7.4 In this model customers who depict constant and predictable demand associated with baseload will be exposed to the same TOU rates as customers who are responsible for peak demand. Eskom has admitted that the TOU rates are not based on cost to serve but the approach seeks to send signals to customers to shift their load – which is an irrational signal if the load cannot sensibly be shifted. This affects households as much as industrial customers where 24/7 constant demand is price higher during peak periods, but the load cannot be shifted - eg. one cannot simply switch off a freezer during peak hours to reduce costs in the same way a smelter of chrome ore cannot be switched off during peak hours to avoid peak charges – the main difference being the quantity of electricity used by the two different customer types in this example.
- 7.5 This pricing approach excludes customers who use energy intensively throughout the day, including the peak demand time. This is a typical example of a pricing system that does not encourage economic growth.

Stakeholder Question 10

Stakeholders are requested to comment on:

- a) whether TOU rates encourage economic allocation of resources and accurate investment decisions from both the demand side and supply side;

-
- | |
|--|
| <ul style="list-style-type: none">b) the reasonableness of charging TOU prices for baseload consumption, particularly during peak energy demand periods; andc) pricing approaches that will lead to proper allocation of costs to customers based on the resources that are used to generate electricity to serve the type of demand – reflecting the cost to serve, regardless of when they need it. |
|--|

8 Indexing for year-on-year price/tariff increases

- 8.1 The final step after determination of the tariff for each category is how the tariffs will be adjusted on a year-to-year basis. An indexed electricity of rate approach implies that the price of electricity is tied to another underlying variable, such as inflation. The indexation of electricity prices should take into account the interest of consumers and not only of supplies. When these interests are not taken care of, it is necessary for NERSA to intervene.
- 8.2 The advantage of indexing is cost savings, which can automatically remain in the company because it encourages licensees to be efficient in their costs rather than adjusting tariffs based on expected future sales. Indexing plays a role in determining industry trends and industry input price that are used to track the unit cost of the industry.
- 8.3 An accurate electricity price forecasting is critical to electricity market participants at distributing and retailing levels. Investors rely on predicted prices to decide their investment strategies, negotiate contracts and hedge risks. Various forecasting techniques can be used including, but not limited to, inflation. Available correlated data also have to be selected to improve the short-term forecasting performance.

| |
|---------------------------------|
| Stakeholder Question 11: |
|---------------------------------|

- | |
|---|
| <ul style="list-style-type: none">a) Stakeholders are requested to comment on the appropriateness of using indexing as a method on increasing approved prices.b) What is the appropriate method of indexing electricity/increasing approved prices?c) Which other indicators can be used to index electricity prices, other than inflation? |
|---|

9 Prudency assessments

- 9.1 Section 16(1) (a) of the ERA states that 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.

- 9.2 It is incumbent upon NERSA to ensure that costs allowed are efficient to enable an efficient licensee to recover the full cost of its licensed activities. To achieve this requirement of the ERA, NERSA will use approved prudence guidelines and benchmark costs.
- 9.3 NERSA will require benchmark costs on capital costs, operation and maintenance costs, life of plant, depreciation per plant and per technology.

10 Applicability of the methodology

- 10.1 The Methodology is subordinate to the requirements of the ERA and the Electricity Pricing Policy. The requirements from these pieces of legislation will, at all times, supersede those of the Methodology where the law will always be the final determinant of any administrative activity.
- 10.2 The Methodology shall be used for the evaluation of a licensee's tariff application.
- 10.3 In the application of the Methodology, NERSA may apply its reasonable judgement after due consideration of what may be in the best interest of licensees, the public and the overall South African economy.
- 10.4 NERSA shall, from time to time, as and when necessary request licensees to submit information and in the manner considered suitable to allow NERSA to analyse such information for the purpose of making decisions on licensees' applications.
- 10.5 Any non-compliance with the procedure set out in this Methodology may be condoned by NERSA on application by licensees. The following factors shall be taken into account by the Energy Regulator in deciding whether to grant condonation:
 - a) The extent or degree of deviation
 - b) The explanation for the deviation
 - c) The impact of the deviation on the achievement of the objectives of the Methodology
 - d) The prejudice to be suffered by licensees, the members of the public and the economy if condonation is granted or not granted.

- 10.6 The development of the Methodology does not preclude the Energy Regulator from applying reasonable judgement on licensees' tariff applications after due consideration of what may be in the best interest of the overall South African economy and the public.

11 Review and Modification of the MYPD Methodology

- 11.1 The Energy Regulator will conduct a review of the MYPD Methodology as and when required to ensure that the contents of the Methodology reflect the current regulatory circumstances. NERSA also recognises that special circumstances may arise that may necessitate changes to be effected to the Methodology. NERSA will continuously incorporate justifiable changes that are considered necessary to immediately capture clarity, transparency and regulatory efficiency benefits.

12 The Consultation Process

- 12.1 Stakeholders are requested to comment in writing on the Consultation Paper on the New Price Determination Methodology. Written comments can be forwarded to mypd@nersa.org.za; hand-delivered to Kulawula House, 526 Madiba Street, Arcadia, Pretoria; or posted to PO Box 40343, Arcadia, 0083, Pretoria. The closing date for the submission of comments is **22 October 2021 at 16:00**.
- 12.2 NERSA will collate all comments received, which will be taken into consideration when the decision is made. Public hearings will be held using MS Teams in line with the COVID-19 restrictions and applicable government regulations, wherein presentations may be made by interested and affected parties.
- 12.3 The process for consultation and decision-making is outlined in the table below.

Table 1: Indicative Timelines

| Task Name | Duration | Start | Finish |
|---|----------------|---------------------|---------------------|
| DRAFT HIGH-LEVEL TIMELINES FOR APPROVAL OF CONSULTATION PAPER TO DETERMINE A NEW PRICE DETERMINATION METHODOLOGY | 37 days | Thu 21/09/09 | Fri 21/10/29 |
| ELS workshop to consider and discuss consultation paper | 1 day | Wed 21/09/22 | Wed 21/09/22 |
| Draft high-level timelines for approval of the consultation paper on the determination of a new price determination methodology | 5 days | Wed 21/09/22 | Tue 21/09/28 |

| | | | |
|---|---------|--------------|--------------|
| ELS workshop to consider and discuss the consultation paper | 1 day | Thu 21/09/23 | Thu 21/09/23 |
| Special Electricity Subcommittee (ELS) meeting to recommend publication of the applications and indicative timelines to the Energy Regulator (ER) | 22 days | Thu 21/09/23 | Fri 21/10/22 |
| Publication of the consultation paper to solicit written stakeholder comments | 22 days | Thu 21/09/23 | Fri 21/10/22 |
| Closing date for stakeholder comments | 5 days | Mon 21/10/25 | Fri 21/10/29 |
| Microsoft Teams public hearings | 6 days | Fri 21/10/29 | Fri 21/11/05 |
| Analysis of stakeholders' comments and drafting the Reasons for Decision (RfD) for ELS consideration | 6 days | Fri 21/11/05 | Fri 21/11/12 |
| Extended ELS workshop (interrogation of the analysis done on the consultation paper and stakeholder comments) Draft Decision and Reasons for Decision | 6 days | Fri 21/11/12 | Fri 21/11/19 |
| Special Energy Regulator decision on methodology | | | |

12.1 Table 2 below shows the indicative timelines that will be published on NERSA website.

Table 2: Public Hearing indicative dates and venues

| PROVINCE | CITY | DATE |
|---------------|-----------------|----------------------------|
| All provinces | Virtual meeting | From 25 to 29 October 2021 |

*The dates of the public hearings might be reviewed/ extended depending on the number of presenters registered and general interest.

12.2 Due to Covid19 restrictions, public hearings will be conducted virtually. Provision will be made for one physical public hearing in Gauteng as the risk will be less in that there will not be any travelling/usage of airports and hotels. NERSA will continue to observe developments in the COVID19 regulations and make amendments where necessary.

12.3 For more information and queries on the above, please contact Mr Thilivhali Nthakheni or Ms Lehuma Masike at the National Energy Regulator of South Africa, Kulawula House, 526 Madiba Street, Arcadia, Pretoria.
Tel: 012 401 4025/4724

Fax: 012 401 4700

End