A SIMPLIFIED COST OF SUPPLY (COS) AND ELECTRICITY TARIFF DESIGN APPROACH FOR MUNICIPAL ELECTRICITY DISTRIBUTORS IN SOUTH AFRICA

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1 Introduction

Electricity utilities are facing the challenge of pivoting their business models due to disruptors such as distributed energy resources. One of the key factors in mitigating the risk of revenue loss is through ensuring cost-reflective electricity tariffs. To understand their costs and the drivers that underpin them, municipalities must conduct Cost of Supply studies (COS).

The National Energy Regulator of South Africa (NERSA) has historically used the Guideline and Benchmarking Method to evaluate and approve municipal electricity tariff applications. However, on 20 October 2022, this method was declared unlawful by the High Court of South Africa and will cease to apply with effect from the 2024/25 municipal financial year. The judgement allowed NERSA one year in which to remedy its previous mistake and adopt a COS approach as of the 2024/2025 municipal financial year [1]. This is in accordance with the Electricity Pricing Policy which requires electricity distributors to undertake COS studies at least once every five years, or when significant structural changes occur, (for example, when there are changes to the customer base, relationships between cost components and sales volumes) [2]. These studies must comply with the framework approved by NERSA.

Sustainable Energy Africa (SEA) developed a COS tool for municipal utilities in South Africa (SA) which Ricardo has enhanced using international best practices and includes the addition of a tariff design module. This resulted in the development of an enhanced V2 (“version 2”) of the standardised COS tool (hereafter referred to as “the COS tool” or “the tool”). The new COS tool enables utilities to understand and visualise their cost versus revenue structures as a function of their cost drivers. It also allows for the separation of the wires business from retail to permit network operators to determine wheeling charges. As part of the South African-German Energy Programme (SAGEN) through funding from the German government and implemented by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), Ricardo successfully supported participating metropolitan electricity distributors in undertaking COS studies using the new COS tool.

2 Cost of Supply Framework

This paper assumes that the reader is familiar with the NERSA Cost of Supply Framework, therefore only a brief summary of the framework is discussed in this section. The COS steps are depicted in Figure 2-1.

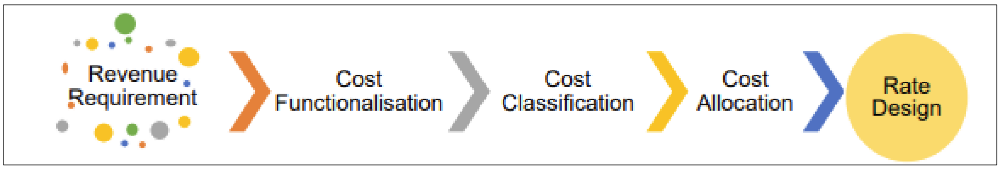

Figure 2-1: NERSA COS Framework Steps [1]

The adopted approach is summarised below:

i. The revenue requirement is the revenue threshold necessary to recover the costs of the licensed service, including an appropriate return. This revenue must be recovered through the retail tariff rates.

ii. The cost functionalisation step assigns the identified expenses among the significant operations of the licensee. This process entails categorising measurable expenditures into functional categories including generation, transmission, distribution, and customer-related activities.
iii. The cost classification step categorises and separates expenses into distinct groupings, including energy, demand, and customer-related costs.
iv. The cost allocation stage distributes the categorised expenses among the relevant classes of service. This process establishes the revenue to be collected from the different rates or customer categories.
v. Finally, the rate design step establishes the rates to be applied in order to collect the allocated rands from the different customer groups. This step also includes the determination of wheeling charges.

3 COS Tool Overview

3.1 Development of the COS Tool

As previously mentioned, SEA developed a simplified COS tool in collaboration with the South African Local Government Association (SALGA) and NERSA. The tool was intended to be used by various municipalities who would readily have the required information available or be able to estimate such inputs. Ricardo conducted extensive work to understand the simplified COS tool and thereafter enhanced the tool using international best practices and ensuring alignment with the NERSA COS Framework. This aimed to augment what some municipalities may already have been working with to make the adoption of the enhanced tool significantly faster and more efficient.

The major gap initially identified in the simplified COS tool was the absence of a demand cost driver. Most COS methodologies include this feature, and the omission of this driver is not in alignment with the NERSA COS Framework. A summary of the changes implemented in the standardised COS tool is provided below.

i. The tool is a multi-year model. The year in which the study is conducted is Year 1. The model recognises that the data is incomplete for Year 1 as the study will be conducted during the course of the financial year. Therefore, the tool includes a baseline year where data is available for the full financial year – this is Year 0. Finally, the cost of supply and tariffs are calculated for the following year – Year 2.
ii. Eskom purchase inputs consist of monthly kWh, kVA and seasonal/Time of Use (TOU) inputs.
iii. There is a provision for depreciation figures to be derived from asset register inputs.
iv. The Average and Excess (A&E) method is used to allocate the demand-driven costs.
v. The asset register is more granular and aligned with the reduced network diagram (RND).
vi. Purchases by time of use are reconciled with sales by time of use.
vii. Network capital costs are allocated using the A&E method.
viii. Demand costs are identified and represented in the results.
ix. The rate design is flexible and interacts with revenue forecast and rate impact simulations.
x. The tool allows for the separation of the wires business from retail to permit network operators to determine wheeling charges.

3.2 Structure of the COS Tool

The model is structured in a manner that incorporates a multi-year perspective regarding data and calculations. This is illustrated in Figure 3-1.

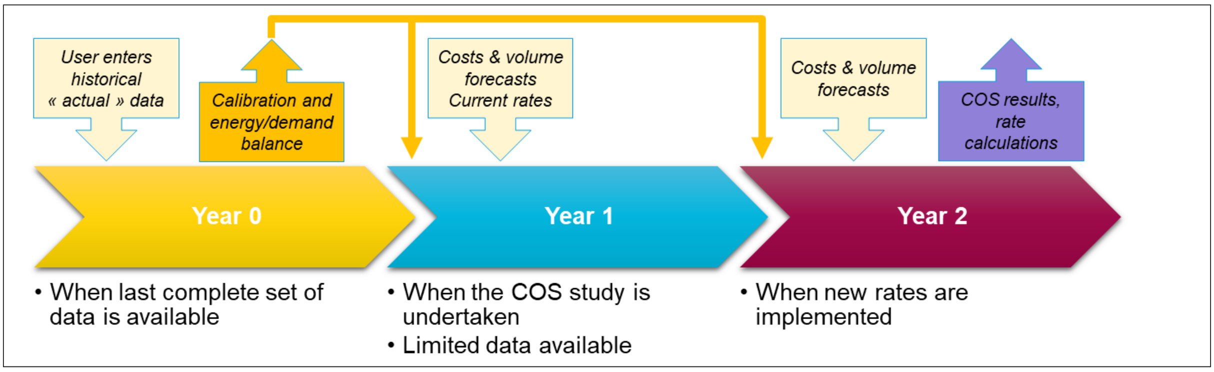

Figure 3-1: Visual illustration of the multi-year nature of the COS tool

In the model, Year 0 is defined as the previous financial period whilst Year 1 refers to the current financial year in which the cost to serve analysis is being conducted. Figure 3-2 depicts a high-level schematic of the model, offering a view of all sheets and calculations involved in the COS study.

The model is supplied with a set of input data which are reflected in the yellow segment of the model flowchart. These inputs include both Eskom and non-Eskom purchase inputs, commercial inputs, operational inputs, the asset register, technical inputs (e.g., loss factors) and other inputs which can be observed in Figure 3-2. An expanded view of this figure is depicted in Appendix A.

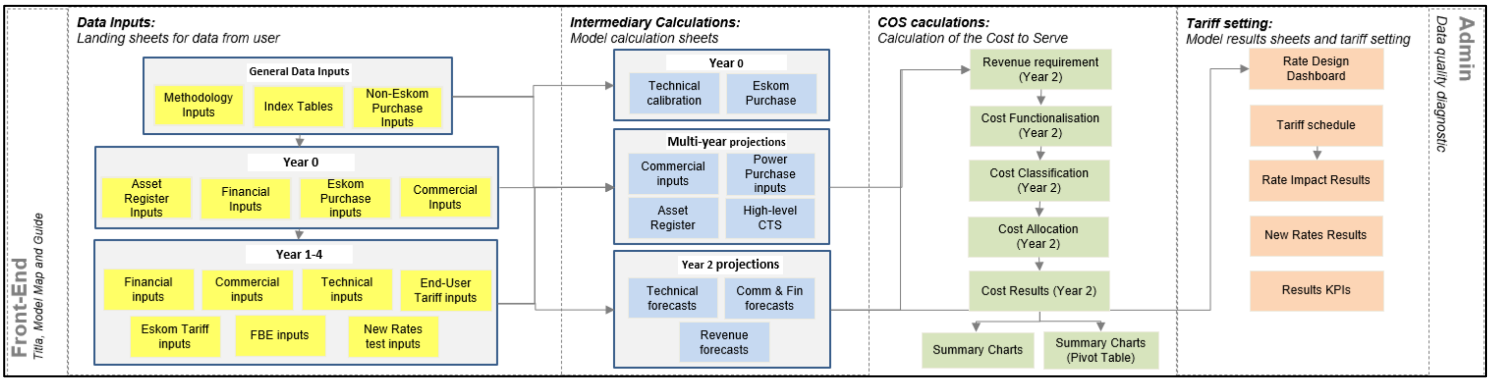

Figure 3-2: Flowchart of the COS model architecture

The revenue requirement is calculated considering the depreciation allowance, capital requirements, purchase costs, network maintenance costs and other operating costs. The total revenue requirement is then broken down by business area, namely the wires and retail portions of the business. This allows for the use of system (UoS)/wheeling charges to be disaggregated from the rest of the costs. The different approaches that can be used to calculate the revenue requirement are, return-based, gross surplus-based, or net surplus-based. Appendix B contains a more detailed explanation of each of these approaches. The approach selected for the wires and retail revenue allowances may differ.

What follows is a technical calibration of losses for Year 0, where technical and non-technical losses are determined based on the sales and purchase inputs to the model. The losses are then allocated by customer category and voltage level. These are then utilised as proxy loss factors for the analysis in subsequent years.

The costs are then broken down by function. The functions utilised are as follows:

- Power purchase costs excluding losses
- Cost of losses
- Other energy purchases
- Capital expenditure
- Depreciation
- Network repairs and maintenance
- Marketing, metering, billing, and vending
- Corporate costs and other operating costs

Cost classification based on demand, energy and customer-driven costs is the next level to which the costs are disaggregated. Further breakdown by season and time of use follows, and lastly, cost allocation by customer category is conducted.

The allocation of demand-driven costs is conducted utilising the average and excess method. Energy purchases along with technical and non-technical losses per customer category are taken into consideration to determine the energy-driven costs. Lastly, customer-driven costs are allocated taking into consideration customer numbers and weighting factors are assigned in relation to the extent of burden imposed by the various customer categories on the system.

The technical calibration done for Year 0, based on the historical data, is used as a basis for the calculations conducted in subsequent years. The forecasts determined for Year 2 then form the basis of the calculations to determine the cost to serve in the upcoming financial period. This leads to the tariff setting module which allows for direct interactions between the cost of supply analysis and tariff setting. This utilises the revenue forecast calculations with three scenarios as follows:

i. Applying the existing tariff rates for Year 1 to the sales forecast for Year 2
ii. Setting tariff rates equal to those necessary to enable full recovery of the costs for Year 2
iii. Revenue determination based on decisions made on the rate design dashboard for various customer categories for Year 2

The rate design dashboard allows the user to make choices, based on the three scenarios above, while the tariff schedule shows the chosen rates based on the user's decisions in the dashboard.

3.3 COS Tool Modes of Operation

COS studies are highly data-intensive and specialised therefore appropriate resources, information and significant time are required to undertake such studies. The COS tool has been enhanced such that it is suitable for both large metropolitan municipalities and smaller municipalities alike. There are two modes available to the user: the advanced mode which is more time-intensive and requires a comprehensive dataset, and the simplified mode where some inputs are pre-populated. This means that municipalities with limited resources may also make use of the COS tool due to its flexibility. The key differences in terms of inputs required for each mode of operation are presented in Table 3-1.

Table 3-1: Table of key differences between the COS tool modes of operation

Mode of Operation	COS Methodology Options	OPEX	Customer Categories	Revenue Requirements	Purchases	Advanced Technical Inputs
Advanced	Fully flexible	Detailed and split by business area and function	Flexible and option to test new categories	Rate of Return or Surplus	Essential to complete	Essential to complete
Simplified	Pre-populated and pre-defined	Pre-defined OPEX categories	Pre-defined (monthly data sufficient)	Surplus only	Year 0 data is essential to complete but the forecast is pre-populated	• Pre-populated • Detailed calculation sheets hidden

4 Case Studies

As previously mentioned, Ricardo successfully supported two participating metropolitan electricity distributors (metros) in conducting COS studies and applying a tariff determination framework for setting electricity tariffs. This was informed by international best practices, the NERSA Framework for Cost of Supply and NRS 058. This work was undertaken as part of the SAGEN programme through funding from the German government and implemented by GIZ. While the specific results of the case studies cannot be disclosed due to Non-Disclosure Agreements (NDA) with the respective municipalities, the process that was followed is presented in the following section.

4.1 COS Process

Ricardo developed a questionnaire to extract qualitative and quantitative data from the two participating metros. Their existing approaches and methods were reviewed, and the COS-relevant processes were established. This included revenue requirement development, cost functionalisation, cost classification, cost allocation and finally tariff setting.

A review of the relevant information and documents was conducted. This data consisted of purchases and sales records, operational and capital budgets for the years under consideration, asset registers, maintenance and refurbishment plans, network diagrams, distributed generation (DG) data, technical and non-technical losses information, customer profiles and maximum demands, tariff schedules and annual reports. This data was analysed and transformed into suitable formats for input into the COS tool.

The revenue requirement was then calculated for each metro using the appropriate approach as determined by the respective metro. The costs were then functionalised, classified, and allocated as described in section 3.2 and unbundled into the wires and retail components. The cost allocation resulted in the determination of the actual cost of supplying different types of customers connected at each voltage level.

There were regular engagements with the metros throughout this process to understand the input data and how it was derived, specifically to clarify any underlying assumptions related to the data and the relevant municipal processes. Adjustments were also made based on the specific requirements or conditions of the metro.

4.2 Interpretation of Results

The "results" presented in this section are indicative of a typical municipal electricity distributor. The results from the case studies cannot be discussed as this is confidential and protected under the respective NDA with each metro. Hence, these results are based on a fictitious municipal electricity distributor to demonstrate the capabilities of the tool. Note that financial year (FY) 2021/2022 refers to Year 1 in this study and FY2022/2023 refers to Year 2.

Figure 4-1 illustrates the forecast of revenue requirements from FY21/22 until FY24/25. The greater proportion of total electricity costs are incurred by the retail part of the business (74%) whilst 26% of the cost is related to the wires business. The following can be noted from this figure:

- The revenue requirement increases substantially.
- The wires business over time still makes up a smaller proportion of the cost. In particular, it gradually decreases from 26% to 23% by FY24/25. The wires costs are dominated by network-related costs, namely network repairs and maintenance, depreciation, cost of losses and other OPEX costs.
- The retail business over time still makes up a larger proportion of the cost, with a gradual increase from 74% to 77% by FY24/25. The dominant retail cost is energy purchases from Eskom.

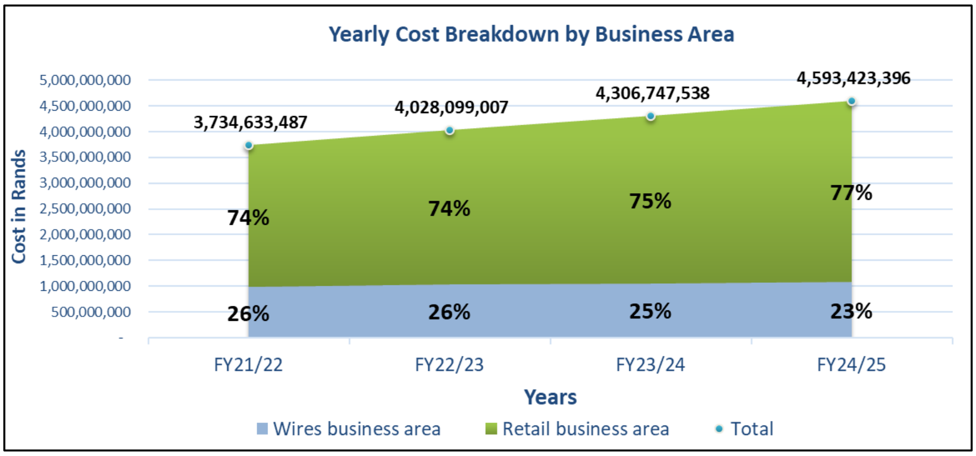

Figure 4-1: Yearly forecast of revenue requirement broken down by business area

Figure 4-2 compares the revenue recovery based on the existing rate regime against the revenue requirement calculated by the cost to serve (CTS) for the fictitious municipality. What can be clearly noted from this chart is that the current rate regime does not provide full cost-reflectivity, with only 81.6% of the costs recovered.

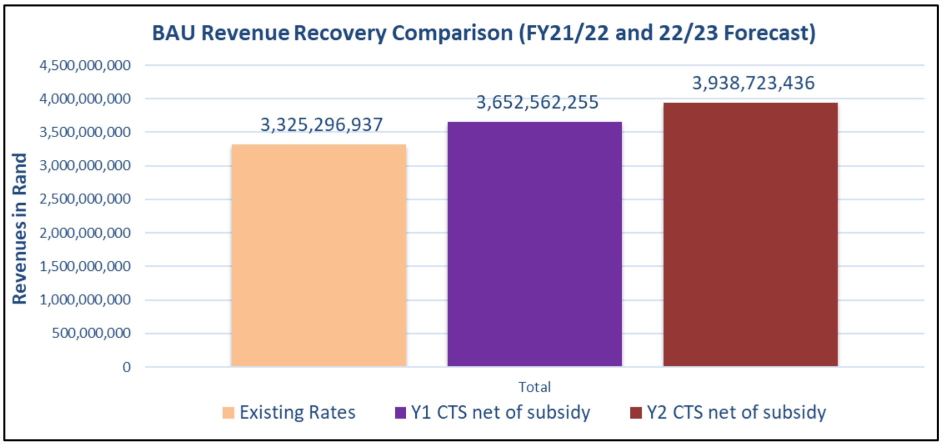

Figure 4-2: Comparison of revenues recovered when comparing the existing rate regime with the CTS results

The results of the cost functionalisation process for total electricity costs for the fictitious municipality are represented in Figure 4-3. As opposed to Figure 4-1, this graph shows the main functions of energy purchases, capital expenditure (CAPEX), as well as operational expenditure (OPEX) and surplus. Figure 4-3 again shows that energy purchases are significant within the cost breakdown and dominate when compared to other costs such as OPEX and surplus. The contribution of CAPEX costs is dependent on the rate of return selected for the study.

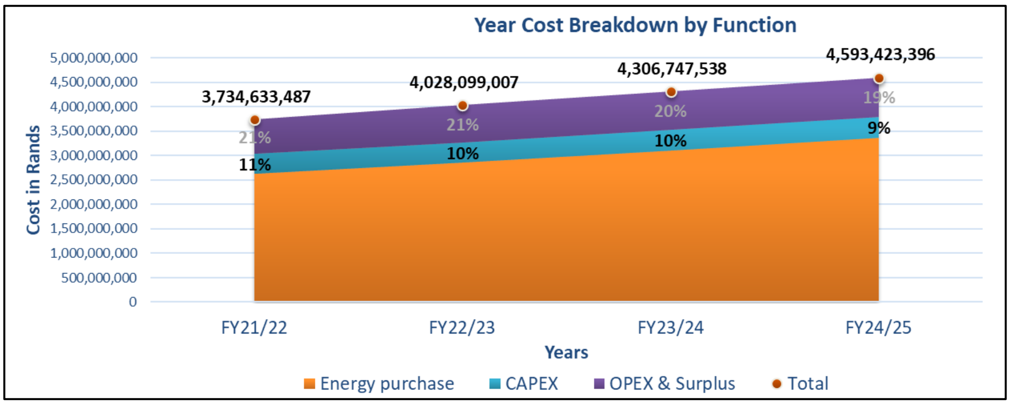

Figure 4-3: Yearly forecast of revenue requirement broken down by function

Figure 4-4 highlights that there is a mismatch between the revenue breakdown and cost breakdown, this is an observation across the majority of municipalities in SA. This figure shows the breakdown of costs into the energy-, demand- and customer-driven cost classifications. This poses a potential problem given the adverse effect on revenues that a change in costs can have, particularly energy-driven costs as this dominates the revenue breakdown. Hence reductions in electricity sales (driven, say, by a greater use of solar photovoltaic (PV) systems by end-use customers) result in a greater reduction in revenue than in costs leading to significant financial stress for the utility.

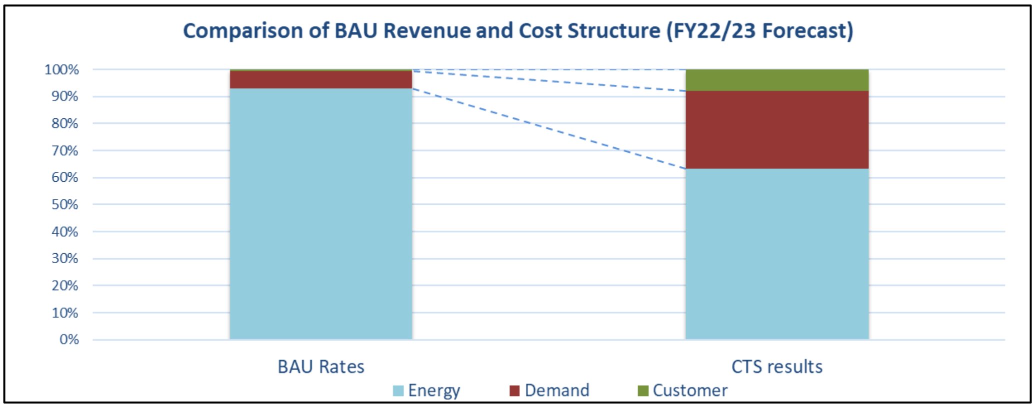

Figure 4-4: Comparison of revenue structure against the cost structure for Year 2

Figure 4-5 depicts the costs per unit of electricity supplied for each customer category. It shows that the customer category incurring the largest costs are the FBE domestic customers and the customer category incurring the lowest costs are the industrial customers. Similar results are expected to be observed in actual South African electricity distributors. Figure 4-5 elaborates on this further by describing the average cost to serve each customer category, broken down by business area. Differences in results between customer classes are mainly driven by differences in voltage level at the point of connection, load factors, coincidence factors, and average specific consumption.

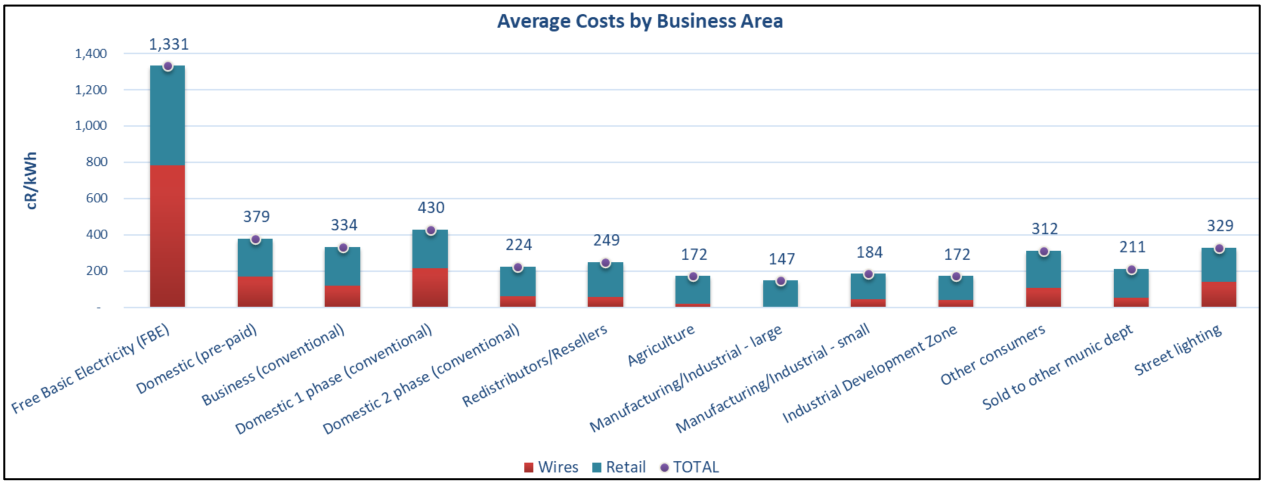

Figure 4-5: Average cost for various customer categories, broken down by business area

Two major conclusions can be made from the results which have been discussed in this section – generally speaking:

- The existing rate regime is not adequate to recover all costs; and
- There is a mismatch between the revenue structure and the cost structure.

The following figure finally highlights how the various customer category rates are either over or under the cost recovery threshold. Those rates that are over the costs offer cross-subsidisation for those that are under. It can be noted that with the existing rate structure, the industrial customers largely cross-subsidise the other customer categories. The business-as-usual (BAU) case is the scenario in which no change is made to the existing Year 1 rates.

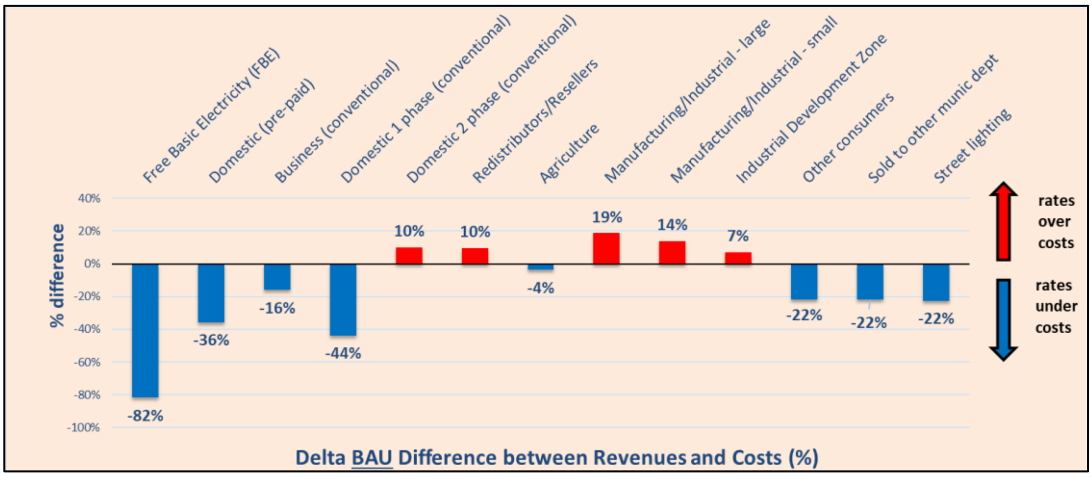

Figure 4-6: Percentage difference between the BAU revenues and costs

4.3 Tariff Design Process

The following section discusses general principles of rate design using the fictitious municipality's COS results. The rate design module of the COS tool allows users to compare the BAU revenues with the cost-to-serve results in Year 2 and thereafter design rates to achieve overall cost-reflectivity.

The tariff design process is summarised in Figure 4-7. The COS tool calculates the overall increase required to reach cost-reflectivity and the user can determine the actual increase to apply to each tariff category.

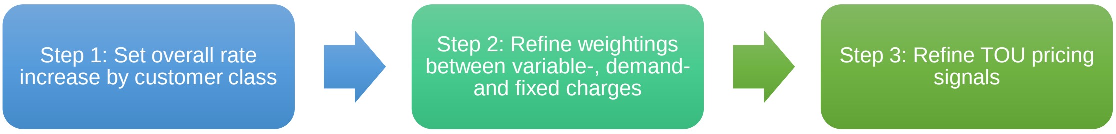

Figure 4-7: Tariff design process

The results of the COS study summarised in the previous section indicated that an 18.4% overall increase is required to make rates cost-reflective for all customer categories. The first step is for the user to determine how this should be applied to the customer categories and if it is feasible to apply such an increase in one year or to phase this in over a few years. Figure 4-8 indicates how these increases may be applied. The user should also refer to Figure 4-6 to identify which customer category rates are over or under the cost recovery threshold. The resulting difference between the revenues from the new rates and the costs is depicted in Appendix C.

Customer Categories	Average Increase in Rates (%)	Increase Required to Reach Full Cost-Reflectivity (%)
Free Basic Electricity (FBE)	0.0%	449.9%
Domestic (pre-paid)	5.0%	55.6%
Business (conventional)	25.0%	18.9%
Domestic 1 phase (conventional)	15.0%	78.1%
Domestic 2 phase (conventional)	15.0%	-9.2%
Redistributors/Resellers	15.0%	-8.8%
Agriculture	15.0%	3.9%
Manufacturing/Industrial - large	8.0%	-15.8%
Manufacturing/Industrial - small	8.0%	-12.3%
Industrial Development Zone	5.0%	-6.5%
Other consumers	27.6%	27.6%
Sold to other munic dept	28.2%	28.2%
Street lighting	29.0%	29.0%

Figure 4-8: Summary of example rate increases, and rate increases required to reach cost-reflectivity (by customer category)

The second step is to refine the weightings between variable charges in c/kWh based on the amount of energy consumed, a demand charge in R/kVA/month based on the maximum demand of the user, and a fixed charge in R/POD/month. This allows the user to implement structural changes to the rates. A summary of the rate structure inputs for the fictitious municipality is given in Figure 4-9. The changes made to the charges experienced by various customer categories resulting from differing increases to different elements of the charges are analysed by considering the impact on all customers in a particular category. The rate impact analysis will be discussed in Section 5.

Rate structure inputs

		1			2			3		
Customer Categories	Type of kVA Charge	Share of Revenues Recovered from Variable Charges (cR/kWh)	BAU	CTS	Share of Revenues Recovered from Demand Charges (R/kVA/month)	BAU	CTS	Share of Revenues Recovered from Fixed Charges (R/POD/month)	BAU	CTS
Free Basic Electricity (FBE)		100.0%	100%	18%	0.0%	0%	69%	0.0%	0%	13%
Domestic (pre-paid)		100.0%	100%	38%	0.0%	0%	48%	0.0%	0%	13%
Business (conventional)		90.0%	100%	43%	0.0%	0%	20%	10.0%	0%	37%
Domestic 1 phase (conventional)		100.0%	100%	34%	0.0%	0%	63%	0.0%	0%	3%
Domestic 2 phase (conventional)		97.8%	98%	65%	0.0%	0%	29%	2.2%	2%	6%
Redistributors/Resellers		93.2%	93%	58%	0.0%	0%	4%	6.8%	7%	38%
Agriculture	per KVA of MD metered	81.0%	81%	84%	16.3%	16%	10%	2.7%	3%	6%
Manufacturing/Industrial - large	per KVA of MD metered	91.7%	92%	98%	8.2%	8%	1%	0.1%	0%	0%
Manufacturing/Industrial - small	per KVA of MD metered	80.0%	90%	69%	12.0%	7%	22%	8.0%	3%	10%
Industrial Development Zone	per KVA of MD metered	90.8%	94%	74%	8.5%	6%	26%	0.7%	0%	1%
Other consumers	per KVA of MD metered	37.8%	38%	46%	5.9%	6%	21%	56.2%	56%	32%
Sold to other munic dept		99.9%	100%	69%	0.0%	0%	31%	0.1%	0%	0%
Street lighting		99.9%	100%	44%	0.0%	0%	56%	0.1%	0%	0%

Figure 4-9: Summary of changes to rate structure

Finally, the TOU pricing signals may be refined by the user. The user may change the rate structure by including TOU and seasonal energy rates for each customer category and including a seasonal demand rate. Figure 4-10 indicates how this may be applied.

Tariff TOU design inputs

Customer Categories	TOU Energy Rates?	Seasonal Energy Rates?	Seasonal Demand Rates?	Peak Pricing Signal	BAU	CTS	Standard Pricing Signal	BAU	CTS	Offpeak Pricing Signal	BAU	CTS
Free Basic Electricity (FBE)	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%
Domestic (pre-paid)	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%
Business (conventional)	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%
Domestic 1 phase (conventional)	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%
Domestic 2 phase (conventional)	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%
Redistributors/Resellers	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%
Agriculture	FALSE	FALSE	FALSE	0%	99%	218%	0%	102%	95%	239%	98%	61%
Manufacturing/Industrial - large	TRUE	TRUE	TRUE	184%	210%	184%	101%	94%	101%	62%	57%	62%
Manufacturing/Industrial - small	TRUE	TRUE	TRUE	162%	194%	162%	100%	90%	86%	60%	54%	80%
Industrial Development Zone	TRUE	TRUE	TRUE	159%	196%	159%	101%	92%	101%	67%	55%	67%
Other consumers	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%
Sold to other munic dept	FALSE	FALSE	FALSE	0%	99%	218%	0%	103%	95%	239%	98%	61%
Street lighting	FALSE	FALSE	FALSE	0%	100%	218%	0%	100%	95%	239%	100%	61%

Figure 4-10: Summary of changes to TOU pricing signals

The rate design decisions will be informed by the utility's specific context and various policies, such as the subsidy policy, the degree of DG penetration, any imperative to stimulate economic activity in the region, etc.

5 Benefits of the COS Tool

5.1 Rate Impact Analysis

Structural changes made to existing rates may affect customers disproportionately. The COS tool enables utilities to undertake rate impact analyses to detect such anomalies before the implementation of new tariffs. Figure 5-1 and Figure 5-2 illustrate this disproportionate effect where Business (conventional) customers with very low consumption experience an exceptionally high increase in their bill compared with customers with higher consumption.

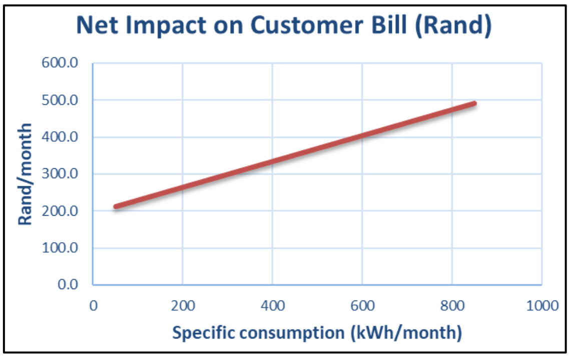

Figure 5-1: Bill impact in R/month by monthly energy consumption - avg. load factor of 50%

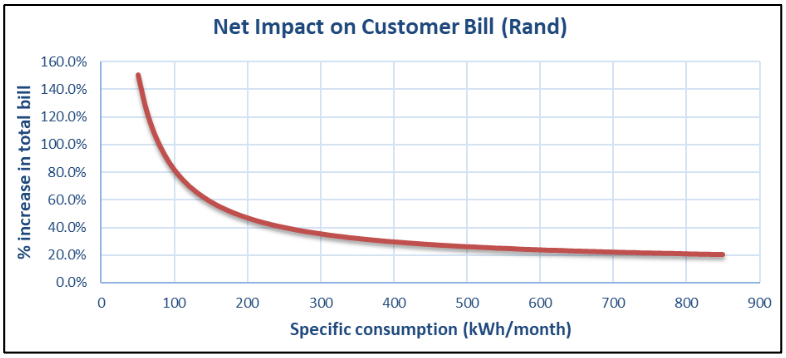

Figure 5-2: Percentage bill increase in R/month by monthly energy consumption - avg. load factor of 50%

5.2 Determination of Wheeling or UoS Charges

The most evident development when considering the current guiding principles for COS, is the emergence of distributed/embedded generation and wheeling which have arisen since both the NERSA COS Framework and NRS 058 were produced. Eskom is currently developing a virtual wheeling framework to enable the trading or wheeling of power in a liberalised electricity market [3]. The framework will be implemented nationally; therefore, electricity distributors will need to undertake COS studies to determine appropriate wheeling charges.

Section 3.1 highlighted that one of the key features of the COS tool is the separation of the wires business from retail to permit network operators to determine wheeling charges. In the tariff setting module of the tool, the user can select the scope of the tariff calculated as "wires only" to determine the component of the tariff that constitutes the charge for the use of the network or system, that is, the wheeling charge. The complete tariff schedule (wires and retail components) and the wires-only charges for the fictitious municipality are indicated in Figure 5-3 and Figure 5-4, respectively.

Tariff Schedule (Year 2)

This sheet summarise the tariff schedule for Year 2 based on inputs on Rate Design Dashboard

Scope of tariffs calculated: Wires+Retail

RATE COMPARISON

New rates for Year 2 (dashboard) (Wires+Retail)

	Standing Charge	Average Demand Rate	Average Energy Rate	Total Average Rate
Customer Categories	Rand/month	Rand/kVA/month	cR/kWh	cR/kWh
Free Basic Electricity (FBE)	-	-	213	213
Domestic (pre-paid)	-	-	256	256
Business (conventional)	194	-	316	351
Domestic 1 phase (conventional)	-	-	278	278
Domestic 2 phase (conventional)	62	-	278	284
Redistributors/Resellers	305	-	293	314
Agriculture	1,041	349	154	190
Manufacturing/Industrial - large	1,404	203	173	189
Manufacturing/Industrial - small	3,461	332	181	227
Industrial Development Zone	6,375	231	175	193
Other consumers	2,362	173	118	312
Sold to other munic dept	519	-	211	211
Street lighting	342	-	328	329

Figure 5-3: Tariff schedule - wires and retail

Tariff Schedule (Year 2)

This sheet summarise the tariff schedule for Year 2 based on inputs on Rate Design Dashboard

Scope of tariffs calculated: Wires only

RATE COMPARISON

New rates for Year 2 (dashboard) (Wires only)

	Standing Charge	Average Demand Rate	Average Energy Rate	Total Average Rate
Customer Categories	Rand/month	Rand/kVA/month	cR/kWh	cR/kWh
Free Basic Electricity (FBE)	-	-	690	690
Domestic (pre-paid)	-	-	168	168
Business (conventional)	67	-	108	120
Domestic 1 phase (conventional)	-	-	213	213
Domestic 2 phase (conventional)	13	-	60	61
Redistributors/Resellers	55	-	53	57
Agriculture	108	36	16	20
Manufacturing/Industrial - large	- 18	- 3	- 2	- 2
Manufacturing/Industrial - small	687	66	36	45
Industrial Development Zone	1,316	48	36	40
Other consumers	823	60	41	109
Sold to other munic dept	133	-	54	54
Street lighting	147	-	141	141

Figure 5-4: Tariff schedule - wires only

A topical question concerning wheeling is to what extent, if at all, should wheeling customers contribute towards cross-subsidies? The answer to this question will depend on the specific jurisdiction and the subsidy policy of the municipality. The COS tool allows the utility to transparently determine this through the allocation of a cross-subsidy weighting factor between the wires and retail business areas. An equal weighting factor of 50%, as indicated in Figure 5-5, indicates that the cross-subsidies for a particular category are evenly split between the wires (wheeling) and retail rates.

Wheeling / Retail: Split of Cross-Subsidy between Business Areas

Customer Categories	Wires Weighting Factor	Retail Weighting Factor	Amount of Cross-Subsidy to Split (Rand)
Free Basic Electricity (FBE)	50%	50%	- 532,618,933.1
Domestic (pre-paid)	50%	50%	- 288,300,630.2
Business (conventional)	50%	50%	3,220,998.7

Figure 5-5: Allocation of the cross-subsidy weighting factor for wheeling rates

6 Add-ons

Alongside the main cost of service model, two add-ons have been created to extend the benefits of the model to the wider industry and to facilitate its implementation.

6.1 D-form Add-on

Every year NERSA receives electricity tariff applications from each electricity distributor in the country and must review these applications timeously for the new tariffs to be implemented before the next financial year. The requirement for tariff applications to be supported by a COS study adds further complexity to this task. Furthermore, some municipalities may have limited experience with COS studies or may not have access to the data required to complete a comprehensive COS study.

To assist NERSA with reviewing COS applications timeously and to support municipalities with such studies as they work towards building their requisite data repositories and/or developing their capabilities, Ricardo developed an add-on to the COS tool which provides for the automated population of the simplified mode of the tool with data from a municipal distribution form (D-form). All municipalities must submit a D-form to NERSA annually therefore this information is readily available. This add-on provides a significant simplification to the COS process for municipalities and the user can thereafter refine this data and populate the simplified mode of the tool with more detailed information where this is available to ensure the results are more accurate. To make use of this feature, the utility must have access to a blank copy of the COS tool, the COS toolbox that contains the add-on, and a completed D-form. Another benefit of this add-on is that it will enable NERSA to peer review applications that may have been prepared using models or approaches other than the COS tool presented in this paper.

6.2 NERSA Benchmarking Tool

Ricardo developed an additional tool to further support NERSA with reviewing COS applications timeously and to avoid the need to review each application line by line to probe for consistency and efficiency. The NERSA Benchmarking tool was developed to enable NERSA to design groups to sort data from various municipalities to allow for appropriate comparison of utilities.

The COS tool calculates several Key Performance Indicators (KPIs) related to technical metrics, profitability, and efficiency. The benchmarking tool allows the user to import up to fifty COS applications and group them for comparison. Utilities with similar characteristics can be grouped, such as metropolitan municipalities. The KPIs from each group are graphed for the regulator to easily compare utilities' performance against the selected metric. A snapshot of the outputs of the benchmarking tool can be seen in Figure 6-1. The lowest KPIs are presented in green and the highest in red, the KPIs around the average value are presented in blue.

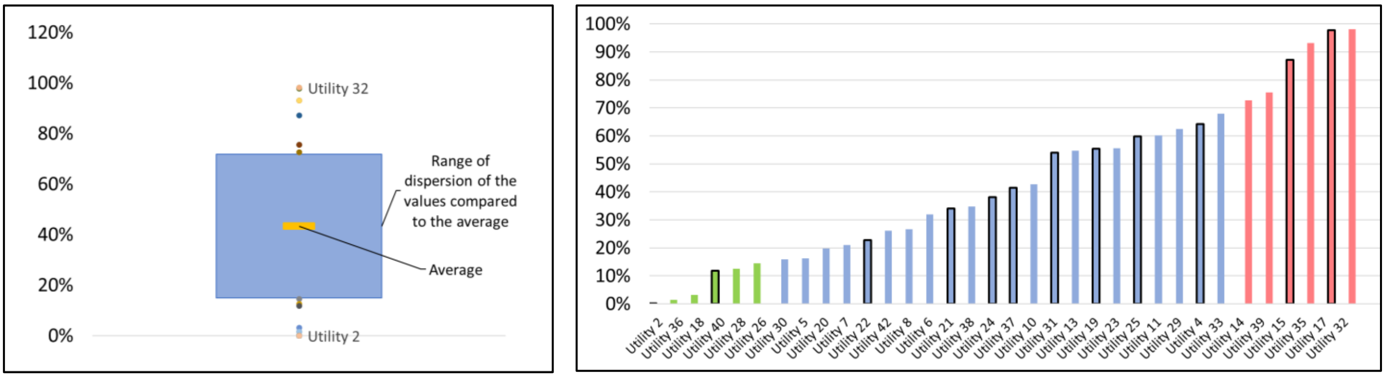

Figure 6-1: Snapshot of the NERSA benchmarking tool outputs

It is important to note that the tool does not define absolute metrics against which to evaluate the performance of the utilities; rather, it is intended to be used for comparative regulation. The outputs of the tool enable the regulator to easily identify outliers or singularities in a group of similar data and therefore, more time can be spent meaningfully assessing such applications. Such a tool would assist NERSA in streamlining the review process, especially if time and resources are a constraining factor.

In addition, it can be seen that certain bars are outlined in black in Figure 6-1. This provides an indication of the overall quality of a utility's submission. The COS tool has several data quality diagnostic tests within the various input sheets to verify if all mandatory inputs have been correctly inputted into the model. The overall data quality score is also measured in the COS tool and is imported by the benchmarking tool to enable the regulator to assess applications for completeness and data quality.

7 Conclusion

The COS tool has been designed according to the NERSA Framework for Cost of Supply, NRS 058 and using international best practices. Hence, the methodology is compliant with the regulator's requirements. It offers a means to standardise COS studies, and in so doing, presents the opportunity for cross-learning between different utilities.

The two modes of operation of the tool ensure that the tool is flexible and adaptable to the needs and capabilities of the utility. This means that smaller municipalities that may make use of the simplified mode also have access to advanced features such as the rate design module and the rate impact analysis.

Section 4 highlighted the benefits for users of the tool. This includes the ability to easily visualise a utility's revenue structure versus cost structure and if the costs are being recovered through existing tariffs. This is essential for a utility to understand its volumetric risk given the increasing penetration of DG. Another important feature of the tool is that the cross-subsidies that exist are transparent and can be intentionally corrected or applied according to the utility's subsidy policy.

Beyond the scope of COS, but very important in the rate-making process, is that the protection of customer interests needs to be considered during the tariff design process as pricing is ultimately subject to utility regulatory oversight. The COS tool aids in achieving this objective through the calculation of transparent and easily understood tariffs.

The market is being liberalised therefore costing methodologies and ratemaking need to follow suit. The COS tool enables utilities to ensure their financial sustainability through the design of cost-reflective tariffs and to meet the future needs of the electricity supply industry through wheeling charges and unbundled tariffs.

8 References

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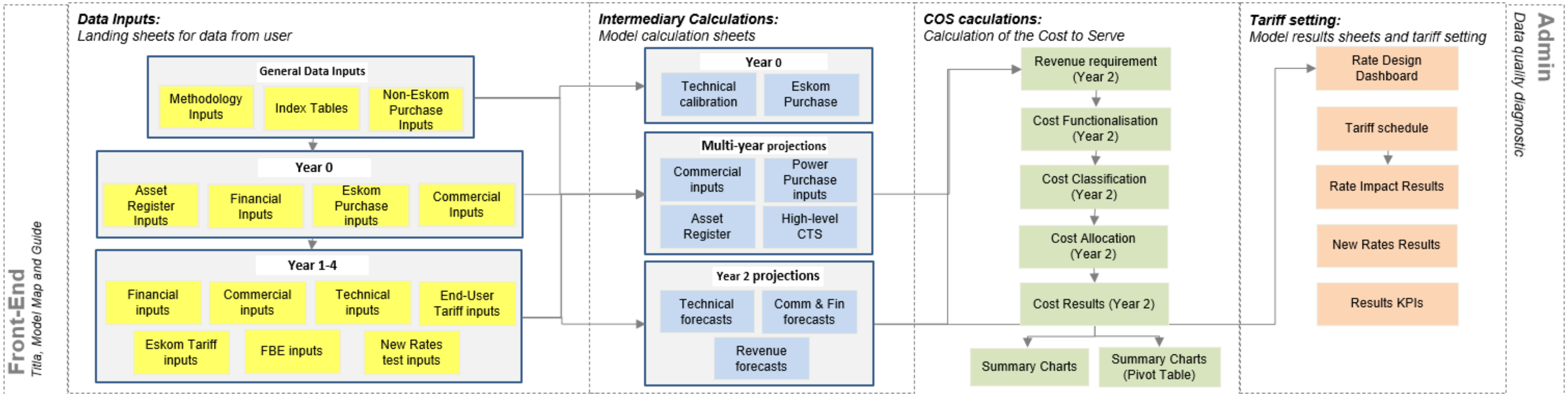
[2] Department of Minerals Resources and Energy, “South African Government,” February 2022. [Online]. Available: https://www.gov.za/sites/default/files/gcis_document/202203/45899gon1747.pdf. [Accessed August 2023].

[3] O. Rantwane, “Virtual wheeling presentation,” Eskom, 2023.

Appendices

Appendix A: Flowchart of the COS model architecture



Appendix B: Revenue Requirement Approaches

Different approaches can be selected by the user to calculate revenue requirements, and a different approach can be selected for – respectively – the wires and the retail revenue allowance.

1. A return-based approach, whereby

$$\boldsymbol{RA}(\boldsymbol{y}) = \boldsymbol{RoR}(\boldsymbol{y}) * \boldsymbol{RAB}\ (\boldsymbol{y}) + \boldsymbol{OPEX}\ (\boldsymbol{y}) + \boldsymbol{Purchases}(\boldsymbol{y}) - \boldsymbol{OR}(\boldsymbol{y})$$

Where:

$RoR(y)$ = Allowable rate of return for Year y

$RAB\ (y)$= Regulatory Asset Base approved and valued for Year y

$OPEX\ (y)$= Approved OPEX budget for Year y

$Purchases(y)$= Total costs of purchasing electricity, net of wheeling

$OR(y)$= Other revenues estimated for Year y

2. A "gross" surplus-based approach, whereby

$$\boldsymbol{RA}(\boldsymbol{y}) = [\boldsymbol{OPEX}\ (\boldsymbol{y}) + \boldsymbol{Purchases}(\boldsymbol{y}) - \boldsymbol{OR}(\boldsymbol{y})] * (\mathbf{1} + \boldsymbol{sG})$$

Where:

$OPEX\ (y)$= Approved OPEX budget for Year y

$Purchases(y)$= Total costs of purchasing electricity, net of wheeling

$OR(y)$= Other revenues estimated for Year y

sG = Gross surplus percentage

3. A "net" surplus-based approach, whereby

$$\boldsymbol{RA}(\boldsymbol{y}) = [\boldsymbol{OPEX}\ (\boldsymbol{y}) - \boldsymbol{OR}(\boldsymbol{y})] * (\mathbf{1} + \boldsymbol{sN}) + \boldsymbol{Purchases}(\boldsymbol{y})$$

Where:

$OPEX\ (y)$= Approved OPEX budget for Year y

$Purchases(y)$= Total costs of purchasing electricity, net of wheeling

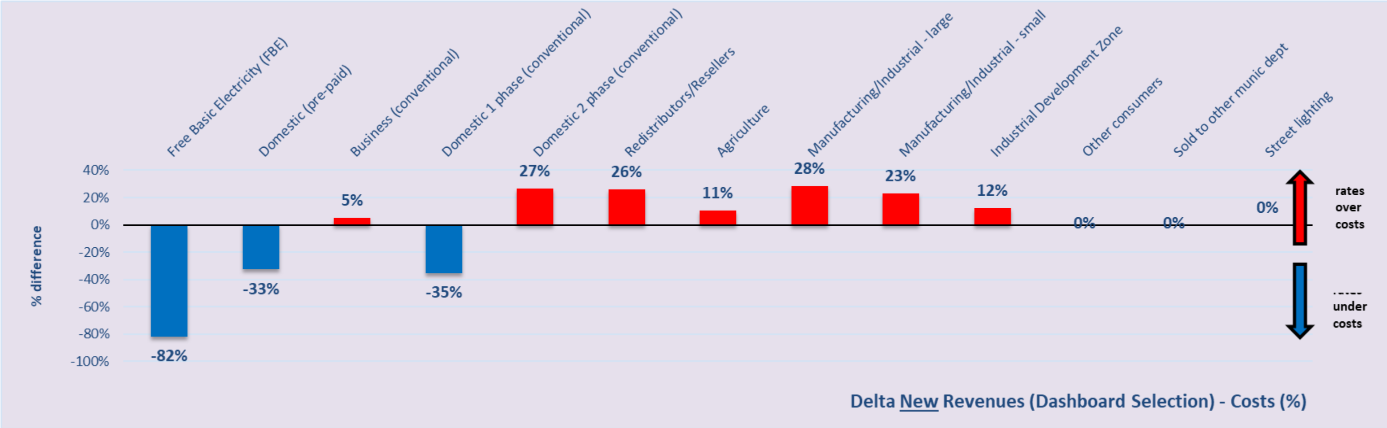
$OR(y)$= Other revenues estimated for Year y

sN= Net surplus percentage

In addition, in the context of either of the three approaches, the user can set a level of maximum allowable system losses $Lmax$. When such a level is set, "purchase costs" used in the formula above exclude costs related to purchasing losses (from Eskom) in excess of $Lmax$. The remaining share of purchase costs is treated as a "disallowed cost" in the study – and it is not reflected in any rate increase or COS calculation.

Appendix C: Revenue Recovery per Customer Category with New Rates

The chart below depicts the revenues recovered from the new rates as per the Tariff Schedule presented in Figure 5-3 compared with the cost to serve results.



Difference between revenues from new rates and costs