A responsive business model for municipal power utilities in a changing electricity market for South Africa: A case study of the City of Ekurhuleni

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Master of Architecture in Sustainable and Energy-Efficient Cities

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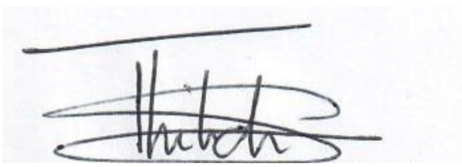
DECLARATION

I declare that this research report is my own unaided work. It is being submitted for the Degree of Master of Architecture in Sustainable and Energy Efficient Cities to the University of Witwatersrand, Johannesburg. It has not been submitted before for any degree or examination at any other University.



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ABSTRACT

As the costs of PV equipment and Levelised Cost of Electricity (LCOE) of distributed PhotoVoltaic (PV) generation continue to decline, more customers of municipal utilities in South Africa are opting for distributed self-generation based on rooftop PV, thereby lowering their electricity costs while also enhancing the reliability of supply. This trend results in municipalities experiencing a decline in sales (and revenue), due to the fact that the revenue is primarily coupled to the volume of electricity consumption/sales. Using the City of Ekurhuleni (COE) as a case study, this study addresses the critical concern over revenue erosion by conceptualising a responsive business model in relation to the increasing adoption of distributed PV generation, with a core motivation of safeguarding municipal revenue from electricity-services. The study collected secondary and primary data from the CoE, as well as secondary data from published academic sources and publicly available online reports.

Data on registered small-scale embedded generation (SSEG) show a growing trend in distributed PV penetration as the related LCOE approached and subsequently dipped below grid-parity in 2013/14. The data were further analysed to determine the city's losses in sales and subsequent loss in revenue. The study also analysed the potential maximum sales likely to be lost should all of the 8500 large customers decide to install distributed rooftop PV.

The results show that the CoE could potentially experience a 30.13% loss of its annual revenue (up to R3.736 billion equivalent) based on current electricity tariffs. A responsive business model option envisages the CoE entering the distributed rooftop PV electricity market by playing alternative roles, such as financing, owning/operating, and installation of the distributed PV systems on its customers' premises. The model further envisages the issuance of green certificates and green-tariffing at discounted rates. The study recommends further research aimed at developing more possible business models for municipal electricity utilities

Keywords: business model, distributed PV generation, levelised cost of electricity (LCOE), municipal electricity utilities, photovoltaic (PV) penetration,

DEDICATION

I dedicate this research report to my lovely wife Phumudzo Candice Thenga and my son Shandukani Tshilidzi Thenga junior; you are both the recipients of my heartfelt gratitude for your long-lasting patience during the course of my studies. Your devotion, support and patience made it easier for me to arrive this far.

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LIST OF ABBREVIATIONS, ACRONYMS AND UNITS OF MEASURE

AMEU	Association of Municipal Electricity Undertaking
BCT	Blockchain Technology
BMC	Business Model Canvass
CoE	City of Ekurhuleni
CoS	Cost of Supply
CSIR	Council for Scientific and Industrial Research
DBSA	Development Bank of South Africa
DER	Distributed Electricity Resources
DG	Distributed Generation
DSM	Demand Side Management
DUoS	Distribution Use of System Charges
EE	Energy Efficiency
ESCo	Energy Services Company
ESI	Electricity Supply Industry
GHG	Greenhouse Gas
HPS	High-Pressure Sodium
IDC	Independent Development Corporation
IoT	Internet of Things
kV	kilovolt
kWh	kilowatt-hour
LCOE	Levelised Cost of Electricity
LED	Light Emitting Diode
LFG	landfill gas to electricity

MW	MegaWatt
MVA	Mega Volt Ampere
NERSA	National Energy Regulator of South Africa
NMD	Notified Maximum Demand
NREL	National Renewable Energy Laboratory
NTL	Non-technical Losses
OUTA	Organization Undoing Tax Abuse
PoD	Point of Delivery
PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable Energy
REFIT	Renewable Energy Feed-In Tariff
REIPP	Renewable Energy Independent Power Producers
RND	Reduced Network Diagram
RPC	Revenue per Customer coupling
SALGA	South African Local Government Association
SANEDI	South African National Energy Development Institute (SANEDI)
SOC	State-Owned Company
SSEG	Small Scale Embedded Generators
TL	Technical Losses

1 INTRODUCTION

Municipal electricity utilities have been in operation for over 100 years in South Africa. They are mainly mandated to distribute electricity to consumers within their licensed area of supply. The Electricity Supply Commission (Escom, also known as Eskom), is a state-owned company (SOC), established in 1923 as a national public utility to operate central electricity generation, transmission and distribution in South Africa (Gaunt, 2008). Eskom currently owns and operates almost all centralised coal-fired power generation stations that are all located in Mpumalanga Province. These stations generate electricity that is transmitted to various parts of the country through transmission networks owned by the same SOC.

Municipal electricity utilities can generate and distribute electricity to customers within their jurisdictions through licenses issued by the National Energy Regulator of South Africa (NERSA). Although their main role has been distribution, an increasing number of municipalities are now interested in generating their own electricity; either for their own use or for distribution to customers. Ongoing developments have also seen the generation component becoming more oligopolistic. In particular, the emergence of grid-connected customers – who are now generating their own electricity on-site for their own consumption with an option of selling the surplus to the grid (also referred to as prosumage) – is drastically changing the current landscape and has a significant impact on the current business models employed in the industry. The increasing costs of grid-electricity and frequent outages (as opposed to climate change mitigation concerns) constitute the key drivers for consumers' search for alternatives such as self-generation. This inevitable shift in the electricity sector and its associated risks to municipal revenue collection calls for responsive adaptation measures by municipal distributors to ensure that their businesses can positively accommodate these disruptive changes, especially through mitigating the negative impact on their revenue.

The main objective of this study is to appraise and conceptualise a responsive business model that would ensure that municipal electricity utilities remain competitive and can mitigate revenue losses across the different stages of the ongoing transitioning of electricity sector and market. There are various approaches implemented by different utilities globally to accelerate and responsively manage similar PV penetration into markets formerly dominated by centralised utilities. Some of the approaches used include the Feed-in-Tariff (FiT) and electricity management incentive schemes, as implemented in Thailand. Other methods used to manage PV penetration include a focus on improving efficiency. This entails the introduction and improvement of relevant efficiency parameters such as cost rationalisation in operations and maintenance, as well as procurement of electricity from sources with a low levelised cost of electricity (LCOE) to improve on profitability. Therefore, municipalities can enhance their profit margins by improving efficiency in electricity management and procuring bulk electricity from alternative cheaper sources that have already reached or out-performed grid parity.

1.1 Background and Context

Currently, South Africa heavily relies on coal for power generation with about 77% of the country's electricity derived from coal. Globally, South Africa is ranked as the sixth largest producer of electricity from coal (Krupa and Burch, 2011). However, this heavy reliance on coal for power generation is diminishing as the industry starts shifting towards the use of renewable energy where mostly industrial and residential customers are investing in distributed PV and other alternative energy sources.

In 2008, the country experienced an energy crisis emanating from electricity supply shortages and subsequent blackouts. This was due to Eskom not building new power stations, which resulted in generation capacity dropping to very low levels, thereby causing blackouts (Ateba and Prinsloo, 2019). Eskom's inability to meet the demand and the subsequent blackouts created the search for remedial action. The available options that could yield immediate results then focused on improving energy efficiency measures through demand-side management. Further measures included addressing the supply side to meet the increased demand through the adoption of renewable energy options implemented both from the supply side and demand side, but these had a relatively longer implementation period.

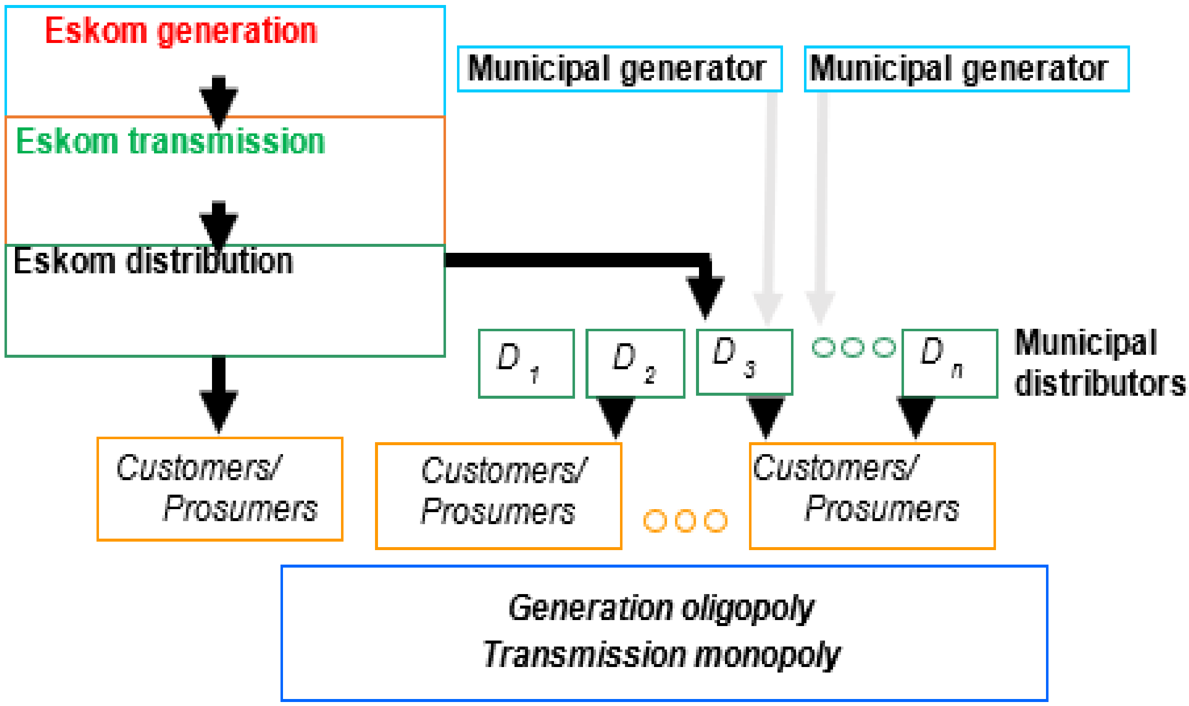

Figure 1.1: The current ESI structure (Source: NERSA, 2012, page 5).

Since then, the South African government has, over the years, committed to change the energy landscape by facilitating investment in renewable energy sources and is being complemented by consumers on similar demand-side initiatives. Multiple policy documents such as the DME (2003), DME (1998) and the DEA (2011), indicate a long track record of interest, even before the 2008 crisis (Jain and Jain, 2017). This commitment was also necessary as a response to the global climate change concerns through the reduction of CO_2 emissions and ensuring sustainable development in line with the country's global commitments to mitigate adverse effects of climate change.

In the translation from policy instruments to implementation, the initial window of the Renewable Energy Independent Power Producer (REIPP) program was launched in 2011 as the first manifestation of the South African Government's commitment to renewable energy. This program was based mainly on solar and wind generation sources and saw the first implementation of Renewable Energy Feed-In-Tariffs (REFIT), which guided tariffs for the different renewable energy technologies. NERSA announced the REFIT in support of the program as the regulatory authority of the energy sector. The REFIT was replaced by the competitive bidding process in the second bidding window in 2012. The REFIT program had resulted in an injection of 6,300MW of renewable energy capacity connected to the national grid (Jain and Jain, 2017).

Over the years, the cost of electricity from renewable resource technologies has dropped dramatically and is expected to continue to drop over the coming years. Due to this drop, many countries have seen the Levelised Cost of Electricity (LCOE) from PV, geothermal, and on-shore wind approaching or already below grid parity (Walwyn and Brent, 2015). Figure 1.2 shows the current renewable energy scenario in South Africa and how it has been exponentially growing since 2013.

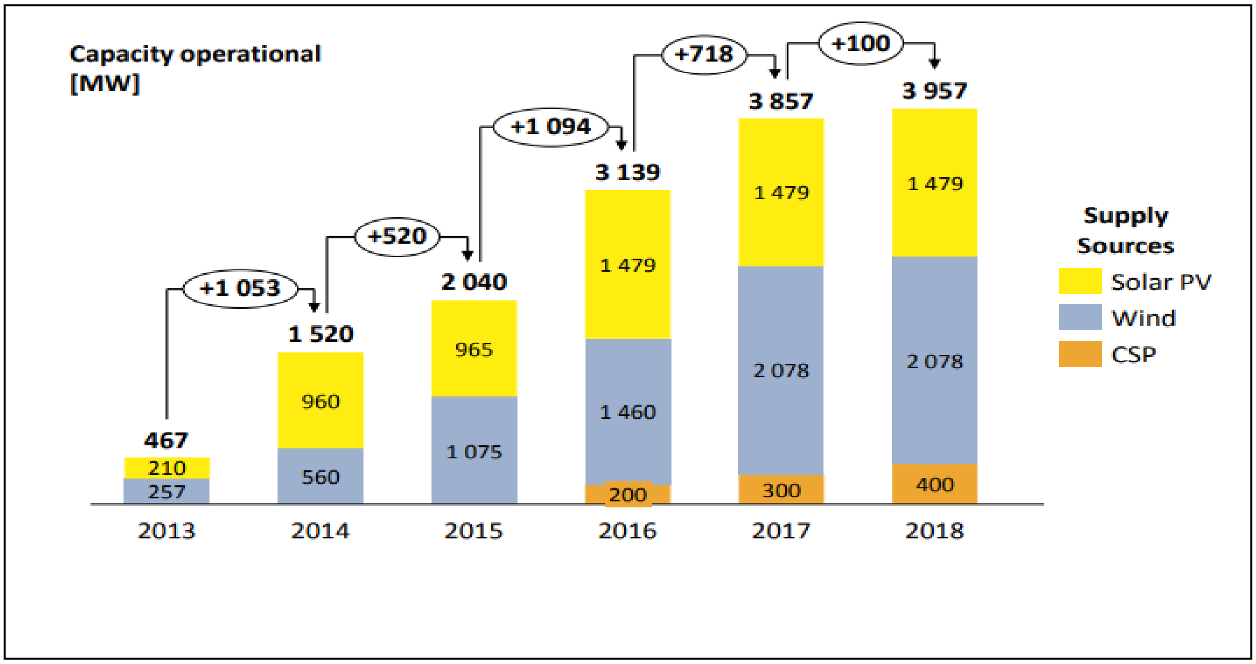

Figure 1.2: South African renewable energy scenario for wind and solar (Source: Calitz et al., page 7).

Distributed generation is also increasing nationally, with most installations occurring in residential areas and on commercial buildings due to the declining LCOE and increasing electricity tariffs from the national grid (for both municipal and Eskom components). Municipal power utilities are, therefore, experiencing an increasing number of applications or requests for grid-connections relating to Small Scale Embedded Generation (SSEG) from their customers. SSEG refers to power generation facilities located at residential, commercial or industrial sites, where electricity is normally consumed (SALGA, 2016). Embedded generation in municipalities goes beyond distributed PV and includes landfill gas-to-electricity and biogas-to-electricity among other technology options. NERSA (2017) defines SSEG as the generation for own consumption at capacity below 1MVA and can be based on any technology. SSEG, therefore, happens on the customer’s side of the meter and at the customer’s own cost. Eskom (2014) notes that SSEG should be synchronized with the municipal utility’s grid.

SSEG is an alternative means of generating electricity for own use by the consumers while reducing the energy costs and with potential benefits of reducing Green House Gas (GHG) emissions (depending on the technology applied). SSEG further encourages those who can afford to procure, own and operate these systems to do so and benefit from accessing cheaper electricity compared to grid-supplied electricity, with the further possibility of feeding any surplus to the grid.

SEA (2017) notes that several municipalities in the country are responding to these dynamics in the energy sector by ensuring that they put in place processes to manage this transition. Such processes entail formally facilitating the uptake of SSEG into the municipal grid, setting SSEG tariffs for surplus export to the grid, and ensuring that an application process is in place for the registration of SSEG systems. Municipalities are also developing their own SSEG projects, which are mainly based on PV but also include biogas and landfill gas to electricity (SALGA, 2016). Municipalities enjoy a larger benefit in owning these systems as they immediately have access to electricity with LCOE below grid parity. Figure 1.3 shows an upward trend for SSEG by municipalities across the country and this means an increase in distributed PV generation within the listed municipalities.

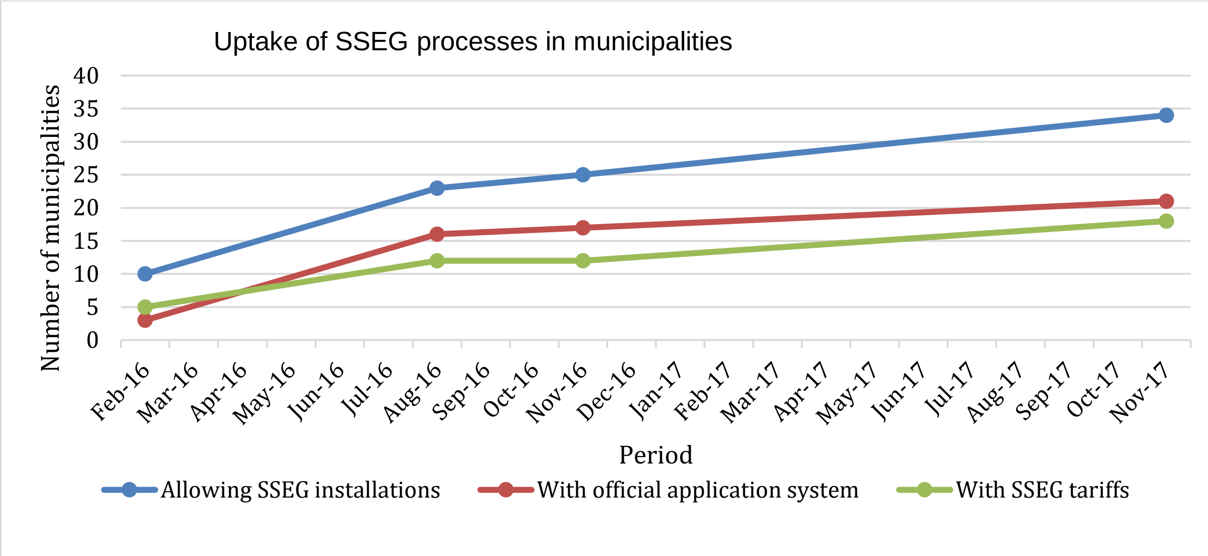

Figure 1.3: SSEG national process set-up trend by municipalities for the period February 2016 to October 2017 (Source: SALGA, 2018, page 2).

1.2 Problem Statement

The study was triggered by the ongoing transition in the electricity sector in South Africa, which is presenting the new trend of prosumage, where consumers are generating their own electricity using various technologies (but mainly based on PV) thus making themselves less dependent on grid electricity. Further interest was triggered by the publication of two journal articles by Korsten et al. (2014) and Mayr et al. (2015) on the impact of PV penetration on municipal revenues. Both studies concluded that there is a global increase in the penetration of distributed renewable energy generation, especially based on distributed rooftop PV, and the phenomenon is also evident in South Africa.

The two studies further concluded that there is a growing risk of negative impact on municipal revenue from declining electricity sales due to the increased self-generation through on-site PV. Municipal power utilities, therefore, must adapt to this change and shift away from their prevailing business-as-usual model. There is, therefore, a need to develop and implement innovative business models that would ensure that such utilities continue to safeguard their revenue while remaining competitive and able to satisfy consumer requirements in a rapidly transforming electricity market.

1.3 The rationale of the study

The current municipal utility business model for electricity distribution in South Africa is showing signs of being negatively affected by prosumage. The increasing installation of distributed rooftop PV by consumers is reducing municipal revenue from electricity sales and the situation is expected to continue deteriorating in the absence of a responsive business model. This study aims to appraise responsive business models towards embracing the current energy transition while ensuring that municipalities mitigate the risk of revenue loss as one of the critical impacts of prosumage. If there is no pro-activeness, municipal utilities might become unsustainable as their key revenue stream (which is currently anchored on volumetric consumption) is eroded.

1.4 Research Questions

Main research question:

What could be a responsive business model for municipal power utilities in terms of safeguarding their revenues while also promoting rooftop PV for distributed generation in the rapidly transforming electricity market of South Africa?

Sub-questions of the study

Based on the City of Ekurhuleni (CoE) as a case study, the sub-questions of the study were structured as follows**:**

- What is the business-as-usual (baseline) electricity revenue trend for the COE?
- What is the extent of the envisaged risk due to electricity revenue erosion, given the scenario of increasing distributed PV generation?
- How could the revenue gap of the CoE be addressed under the increasing rooftop distributed PV generation scenario?

1.5 Research objective and working hypothesis

Guided by the overall research question and related sub-questions, the overall objective of the study is to conceptualise a responsive business model for municipal power utilities in South Africa that ensures that their revenue streams are enhanced, while also allowing them to promote distributed generation with rooftop PV technology (one of the key alternatives to grid-supplied electricity). Arising from this objective, and with key insights from the prevailing trends on PV's LCOE and the innovations around business modelling, prosumage (especially through distributed rooftop PV) is becoming a preferred solution for consumers to mitigate the spiralling grid-electricity tariffs while also enhancing energy security. In response, municipal distributors can innovate their business models to safeguard municipal revenue under the increasing adoption of distributed rooftop PV technologies for electricity generation.

A responsive business model could, for example, entail a shift from the focus on volumetric sales-units (as the main component of revenue determination) to a tariff structure that contains a fixed charge component for recovering fixed costs associated with the delivery of electricity to consumers and other components. The new business model could further include facilitation of financing schemes and supporting technical services for the installation of SSEG, municipal-owned generation in small and large scale, as well as interactive grid-connection of SSEG coupled with appropriate tariffs. Other than promoting the growth of alternative energy sources, such activities will also generate additional revenue streams for municipal utilities from activities such as advisory, financing income and licensing fees. In this case, the CoE will act as a central hub to coordinate all activities focused on promotion of SSEG.

1.6 Research approach

The study primarily employs a qualitative approach but also encompassing quantitative elements where quantitative data are presented and analysed in relation to the purposely selected case study. Qualitative research is mainly based on non-numerical data to answer a research question, while also relying on non-statistical (qualitative) methods of data analysis. Bui (2014) notes that qualitative data are words in the form of a story. Qualitative research has different variations, such as case study, phenomenology, grounded theory, ethnography and participatory action research. Qualitative research also involves establishing an interim theory and utilises the data collected in various ways to inform the formulation of the theory and related conclusions. Quantitative research, however, differs from qualitative research in that it primarily collects numerical data, which are then subjected to statistical analysis towards testing the validity of a theory-guided hypothesis.

1.7 Limitations of the Study

The study seeks to identify and explore the parameters relevant to mitigate the effect of revenue erosion as a result of increasing prosumage driven by distributed rooftop PV, based on a case study of CoE. This was mainly based on the availability and access to the data required, and the researcher’s familiarity with the case (as a municipal power utility employee). However, this also necessitated upfront acknowledgement that this is not necessarily a representative case of municipal utilities in South Africa. The researcher being in the employ of CoE could pose the risk of blinded in terms of curiosity, and his readiness to reflect critically on the problem and the quality or adequacy of the related data. Further limitations include the fact that the research does not address other factors constraining municipal utility efficiency thus impacting revenue

1.8 Delimitation of scope

Given the conceptual nature of the responsive model;

- No revenue modelling was done to allow a comparison of revenue flow under the proposed model versus business-as-usual scenario. This, therefore, calls for a more detailed study dedicated to such revenue modelling and evaluation;
- No implementation strategy was explored in terms of how the existing (business-as-usual) model could be transformed into the proposed responsive model in a manner that facilitates expedited implementation with systematic mitigation of disruptions;
- Co-benefits and spin-offs, such as climate change mitigation impact (or even possible costs), have not been factored into the model. This would thus require additional investigation to quantify the impact of the co-benefits/costs on the revenue.

1.9 Definitions of the key terms used in the study

This section presents an overview of the key terms used in the study as well as their core definitions.

Business model: this is a management tool used to design, implement, operate, change and control a business.

Business Model Canvass (BMC): this is a method or tool used for describing, assessing and improving/transforming business models.

Capacity charge: a monthly charge aimed at recovering the costs of demand placed on the electricity grid when measured in available Ampere, irrespective of volumetric electricity consumption (in kWh units).

Centralised generation**:** centralised generation occurs further from the point of consumption and especially within large generation plants, which in turn warrant transmission and distribution, as well as retail.

Cost of Supply (CoS): this is the total of all costs associated with the delivery of electricity to the consumers and would include the capital costs of related assets, all other costs, such as maintenance costs, back-office operations, as well as related technical and non-technical losses.

Death spiral: this is an unsustainable state (in the operational model of a utility) which occurs when the electricity sales drop as a result of customers opting for alternative sources of electricity, thus resulting in a utility being unable to generate adequate revenue to cover its costs, especially under the common practice or business model, where the utility's revenue constitutes primarily of a simple tariff coupled to units sold.

Decoupling electricity revenue from sales: this entails the disassociation of the revenue and profits of a utility from the volume sales of electricity. Decoupling allows a utility to apply alternative revenue models with the aim of conserving revenue, mitigating the cost and thus enhancing profitability.

Demand charge: in contrast to capacity charge, this is a seasonally differentiated charge based on the highest demand (measured in kVA) registered during a billing month for all periods (or only those specified).

Demand Side Management (DSM): this is a process aimed at managing electricity resources on the customer's side to reduce the load demand as well as overall consumption. DSM involves the implementation of various utility or customer-driven programs, such as load management, shifting time-of-use, conservation through energy efficiency interventions and/or self-generation/prosumage.

De-risk taking steps aimed at reducing the risk of possible or foreseen financial loss.

Distribution network: as part of a country's national grid network, this is the grid network normally operates at voltage levels below 132kV and intended for facilitating electricity delivery to the consumer (point of consumption).

Distributed generation (also referred to as decentralised/dispersed generation): this is the generation of electricity that occurs closer to the point of consumption (Brown and Sappington, 2018). It enhances reliability and quality of power and also minimises line losses in the transmission/distribution stages.

Eco-power: this is energy that is generated from sources that are friendly to the environment.

Electricity Supply Industry (ESI): this is the ecosystem of a country's electricity supply value chain which includes the v components of generation, transmission, distribution and resellers. It also entails the related policy and regulatory frameworks as well as the institutional structures that govern the industry.

Electricity tariffs: this is a structured charge-rate used by electricity utilities for charging customers to recover the costs of supplying electricity services. For South Africa, this is based on NERSA's cost of supply guide, and is commonly constituted of three elements: costs that vary with customer numbers and service intensity (R/month), costs that vary with capacity/demand (kVA) and costs that vary with energy (kWh).

Energy efficiency: involves reducing the amount of energy required to provide a service without compromising the quality.

eVenus: a financial system software package used by CoE and other South African municipalities for purposes of storing and processing financial data.

Feed-In-Tariff: this is a payment framework used to compensate electricity generators who generate and feed electricity into the grid.

Fixed charge: Monthly charge to recover the costs of the administration of the account, such as meter reading, billing and meter capital. The fixed charge is applicable whether the customer consumes electricity or not. The cost of back-office operations of the power utility, therefore, constitutes a key contributing factor to the level of a fixed charge.

Green power: these are renewable energy resources that provide substantial environmental benefits.

Levelised Cost of Electricity (LCOE): this is a measure or benchmarking tool used to assess the cost-effectiveness of different electricity generation technologies. It estimates the cost per unit of electricity generated over the entire lifespan of the generating unit when all applicable costs are included.

Licensed area of supply: an area for which the National Energy Regulator of South Africa has issued a license to a power utility, such as CoE, under the provisions of the Energy Regulation Act of August 2006 (as amended) for the supply of electricity. CoE tariffs would, therefore, be only applicable within jurisdiction where CoE is licensed to supply electricity by NERSA.

Net-metering: this is a technological intervention that facilitates the monitoring of the bidirectional flow of electricity between the distribution network/grid and customer to capture and record what the customer imports from the grid versus exports to the grid within a specific period.

Network Access Charge (NAC): a tariff component, per kVA registered, based on the highest demand registered over a rolling 12-month period, during peak and standard hours. In the case of a new connection or new account holder, the customer NAC shall be deemed equal to the registered maximum demand for the first month.

Non-Technical Losses (NTL): these are losses associated with non-billed or billed but not paid-for electricity-consumption. This contrasts with technical losses commonly associated with transmission and distribution of electricity.

Notified Maximum Demand: the maximum demand notified in writing by a power utility, such as CoE, and accepted by the bulk supplier, such as Eskom. This is determined by the utility based on the requirements of its customers.

Prosumers (prosumage): consumers of grid-electricity who also generate their own electricity on-site, especially while interactively connected to the grid, such that they have an option of selling their surplus to the grid.

Revenue conservation: Mitigating the revenue loss arising from reduced electricity sales within a rapidly transforming electricity/energy market, especially due to distributed generation and prosumage.

Rooftop photovoltaic (PV) system**:** this is a PV system that is mounted on the roof of a building, such that the size of the system is subject to the size of the roof area and the energy requirement of the building when used as some of the key system-sizing criteria.

Small Scale Embedded Generation: refers to power generation facilities, located at residential, commercial or industrial sites, where electricity is generally also consumed. The generation is, therefore, primarily intended for the user’s consumption, and only the surplus is exported to the grid.

Wheeling: this refers to the transportation of electricity from the generator to the consumer using the grid owned by a third party.

1.10 Outline of the research report

This section provides the outline of the chapters in relation to the research objective, and related sub-questions.

Chapter 1 presents the background and context of the study and includes an introduction that focuses on the current perspective and trends in distributed PV generation, and six other sub-themes which are: problem statement, the rationale of the study, main research question, definitions and working hypothesis, research approach and limitation and delimitation of the study. The chapter also highlights the changing environment in the energy sector from a centralised to a decentralised electricity market with increasing prosumage, especially driven by distributed rooftop PV generation and the impact of this change on the business model of municipal power utilities.

Chapter 2 presents an appraisal of related studies based on the key theoretical themes of the study. The key themes include the impact of the adoption of distributed PV generation on municipal finances, data management and reporting, innovations around business models for utilities in response to distributed PV generation and the levelised cost of PV generation versus grid parity.

Chapter 3 presents the overall research approach, as well as the research methodology used to collect and analyse the data to derive sub-finding (tools/instruments) towards a resolution of the research question.

Chapter 4 presents and analyses the data on the first sub-question which relates to the business-as-usual (baseline) revenue performance trend of CoE. This is then followed through with the derivation of sub-findings, which are carried over to the overall findings of the study in Chapter 7.

Chapter 5 presents and analyses data on the second sub-question, which covers the magnitude of revenue erosion under distributed rooftop PV, as well as the sub-question on the identification of parameters that would be relevant towards mitigating the risk of revenue erosion.

Chapter 6 presents the conceptualisation of a responsive business model aimed at addressing the revenue gap. This is based on overall consolidation of previous findings to address the overall research question and application of the business model canvass.

Chapter 7 presents the overall conclusions and recommendations of the study. Further information is provided in Appendices at the end of the research report. The appendices cover data on cumulative SSEG penetration in CoE, consolidated CoE electricity sales, breakdown of municipal street lighting infrastructure, and transcripts of interviews with industry experts who served as participants of this study.

The study also outlines a list of references and appendices. Appendix A: Notified maximum demand per town, Appendix B: Cumulative SSEG penetration in CoE, Appendix C: Breakdown of Eskom costs to CoE per customer category - 2016/17, Appendix D: Breakdown of Eskom costs per customer category, 2017/18, Appendix E: Total costs of supply for CoE for 2016/17, Appendix F: Total costs of supply for CoE for 2017/18, Appendix G: Electricity sales by calendar years, Appendix H: Annual CoE Electricity Sales, Appendix I: Eskom bulk purchases versus CoE sales, Appendix J: Breakdown of municipal street lighting infrastructure, Appendix K: Interview transcript with SALGA official, Appendix L: Interview transcript with industry expert, Appendix M: Interview transcript with Civic Group(OUTA), Appendix N: Interview transcript with Municipal official, Appendix O: Interview transcript with NERSA official, Appendix P: Interview transcript with Financier and Appendix Q: Wits research ethics clearance certificate

2 LITERATURE REVIEW

This chapter appraises previous studies on the subject matter as reported in diverse sources such as academic publications, technical reports, government policies, regulations or legislation. The key themes focus on electricity utility operations globally and related responses to the increasing adoption of distributed PV generation.

The literature is reviewed along the following key themes:

- Business modelling theory and background;
- The current municipal utility business model;
- Innovations in utilities' business models;
- The impact of distributed PV on the current municipal utility business model;
- The Cost of Supply (CoS) and tariff design;
- Operational efficiency parameters;
- The Levelised Cost of Electricity (LCOE) of PV versus grid parity;
- Data management and transacting; and
- Consolidation of insights to guide the study

2.1 Business Modelling: Theory and Background

2.1.1 Introduction

The “business model” concept has been attracting the attention of academics and business practitioners since the 1980s. Horvath and Szabo (2018) notes that there are various approaches to business modelling but there is no commonly accepted definition for this concept. However, Tongsopit et al. (2016) argue that the purposes of a business model, amongst others, include bringing new technologies into the market and also serving as a “management tool to design, implement, operate, change and control a business”. In the utilities sector, a business model describes how a utility creates and delivers its value propositions, as well as how it collects revenue for the value delivered.

In the distributed PV generation perspective, an innovative business plan would therefore be expected to assist in increasing solar PV penetration by removing barriers to the adoption of PV technology as well as improving on the revenue of the utility. Horvath and Szabo (2018) identify four key components of a business model: key resources, key processes, value proposition for customers, and profit from customers (also called cost structure). These components of the business model are used to tell a story of how any business operates by identifying its customers, what their perceived value is and how to provide the perceived value at an acceptable cost *(ibid)*. Osterwalder and Pigneur (2010) described a business model as the “rationale on how an organization creates, delivers and captures value”. Another complementary term, business model innovation, is also relevant in that it makes it possible for businesses to create or enhance uniqueness in their value proposition. Horvath and Szabo (2018) state that innovation helps organisations gain access to new markets and achieve long term competitive advantage. Horvath and Szabo (2018) have introduced the Business Model Canvas (BMC) as a tool for visualising existing and new business models.

2.1.2 The Business Model Canvas (BMC) and its Application

The business model canvass (BMC) method or tool is widely used as a language for describing, assessing and transforming business models (Osterwalder and Pigneur, 2010). The tool is used to define a business model in terms of the nine blocks as listed on Table 2.1 and explained in Table 2.2. The nine blocks can be summarised into four main components which are customers, value proposition, infrastructure and the financials as shown in Figure 2.1. The tool has been extensively tested in practice and proven to be effective in facilitating stakeholders conceptualise and operationalise their business strategies.

<table>
<tr><td rowspan="2">Key partners (KP)</td><td>Key activities (KA)</td><td rowspan="2">Value proposition (VP)</td><td>Customer relationships (CR)</td><td rowspan="2">Customer segments (CS)</td></tr>
<tr><td>Key resources (KR)</td><td>Channels (CH)</td></tr>
<tr><td colspan="2">Cost structure (C$)</td><td colspan="3">Revenue streams (R$)</td></tr>
</table>

Table 2.1: The Business Model Canvas (BMC) (Source: Osterwalder and Pigneur, 2010 page 44).

Value propositions (VP)	The goods and services offered and their distinguishing advantage ● What problem are you solving, or what customers' need are you meeting?
Key activities (KA)	The most important activities in executing the value proposition. ● Important things you need to do to make the business model work. ● What expertise do you require to make the business model work to deliver the value proposition?
Key resources (KR)	The resources necessary to create the value for the customer ● What assets are important to make the business model work (e.g., for production, transportation and human capital)?
Key partners networks (KP)	Relationships considered essential to accomplishing the value proposition. ● Who are the key partners and suppliers, and what are we acquiring from partners, what activities are they going to perform?
Customer segments (CS)	The specific target market(s) intended to be served ● Who are your customers, and why would they buy your product?

Channels ((CH	The proposed channels of distribution. ● How does your product get to your customers? How will you be selling your product
Customer relationship (CR)	The type of relationship the firm wants with its customers ● How do I get customers, keep them and grow them?
Cost structure	Characteristics of the cost and expense structure. ● What are the costs and expenses to operate the business model, key activities to pay for? What are the fixed costs, what are the operational costs?
Revenue streams	The way the firm will make money, how it is paid, and pricing. ● What value is the customer paying for? What is the strategy by which you can capture that value?

Table 2.2: Nine blocks for a Business Model summarized (Source: Osterwalder and Pigneur, 2010 page 1-40).

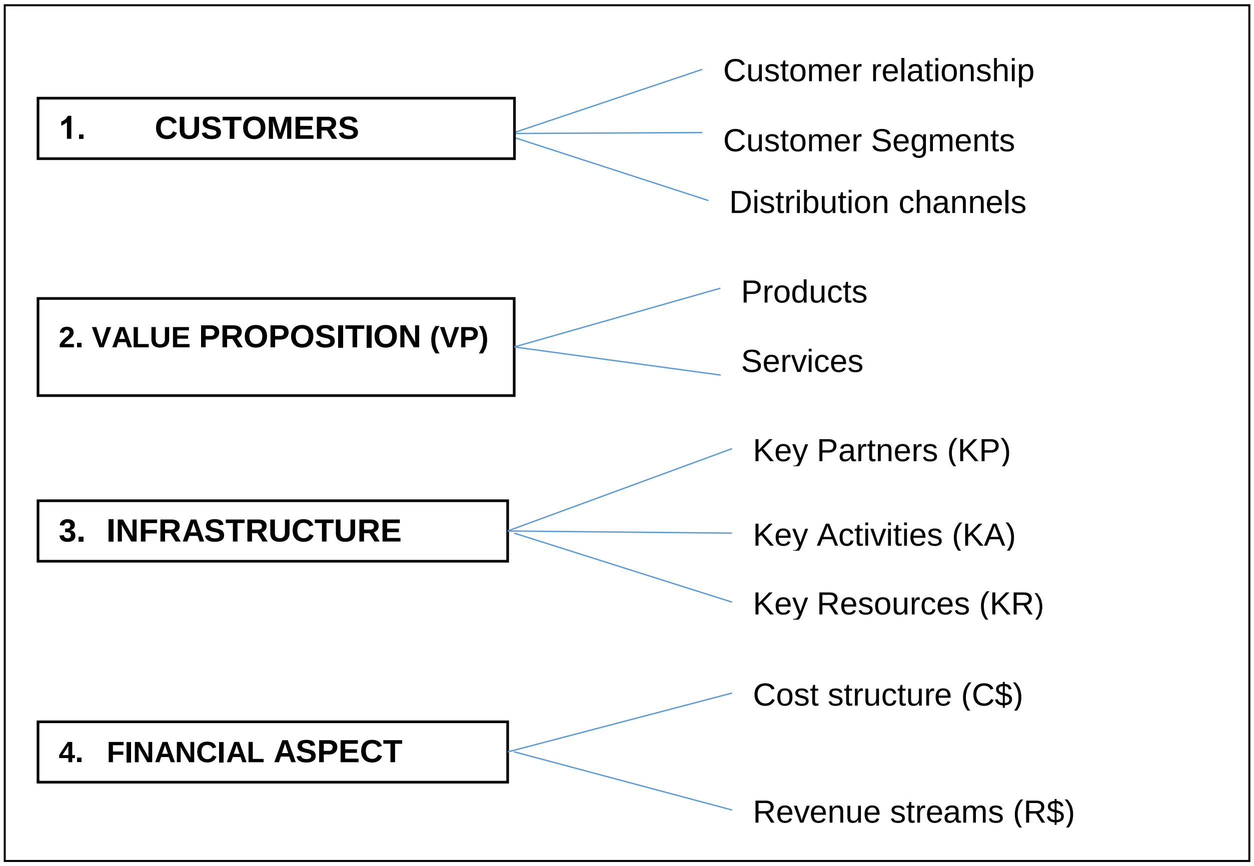

Figure 2.1: Summarised representation of the nine blocks of the BMC

2.2 Current Municipal Business Model

Within the electricity market, a business model is the way a utility delivers value to its customers, and especially how it entices the customers to pay for the value delivered as well as how the utility manages these payments to ensure ongoing profitability. A business model thus makes it possible to analyse and make "comparison of the markets in a structured way, thus providing the basis for the identification of critical success factors" (Richter, 2012:2484). A business model is, therefore, characterized by four key elements:

- Value proposition (refers to products or services offered by the utility to its customers)
- Customer interface (refers to the utility's channels of interaction with its customers)
- Infrastructure (refers to the utility's assets required to create and deliver the value proposition)
- Revenue model (refers to all the revenue and costs associated with the selling of the value proposition)

2.2.1 The current structure of the municipal value chain

The electricity value chain shown in Figure 2.2 shows the stakeholders involved from the generation of electricity to consumption by final end-users. The value chain includes stakeholders that represent the required key partners for CoE in the delivery of the value proposition.

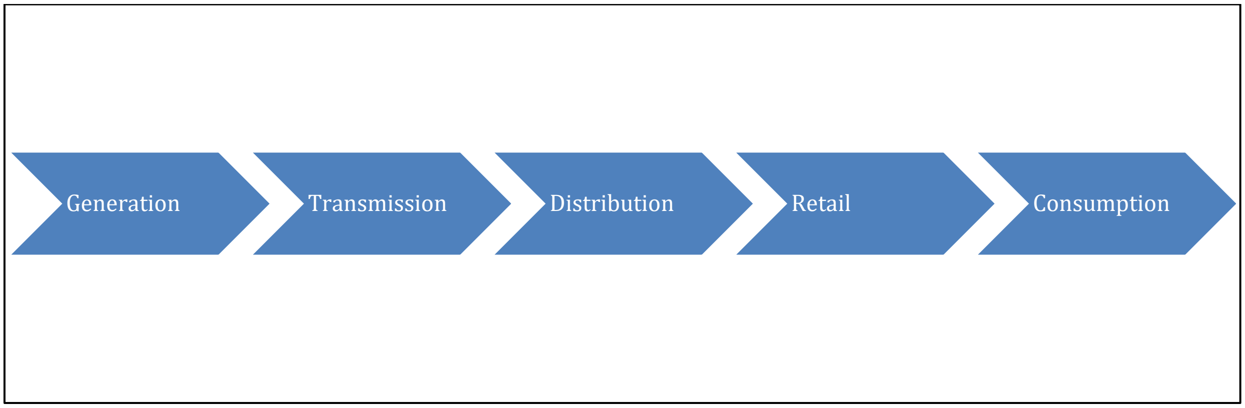

Figure 2.2: Electricity value chain (Source: Richter, 2012, page 2486).

The first part of this value chain is generation, which is defined as the transformation of primary energy sources to electricity (Richter, 2012). For South Africa, the largest share of electricity generation (estimated at 90%) is performed by Eskom, while some municipalities own and operate relatively smaller generation plants.

The second part of the value chain is the transmission network assets, whose function is the transmission of electricity over long distances (sometimes over hundreds or thousands of kilometres) to key consumption nodes, such as cities. Transmission network is designed to handle higher voltage levels of above 132kV from the generation plants to points of distribution and consumption. Eskom (as a state utility) owns and operates the largest portion of the transmission network in South Africa. The other portion is owned and operated by municipalities, such as the CoE.

The next part of the value chain is the distribution network, and this is the part of the value chain currently dominated by municipalities. This is the portion of the network that operates at voltages equal-to-and-below 132kV. It involves the conveying of electricity to the end-user's primary connection points for subsequent consumption.

The retail portion of the value chain is the link between the distributing utility and the customer. It caters for administrative issues, such as communication with customers and billing. It is the interface between upstream value chain stakeholders and the final electricity consumers.

For this value chain to function, the Government of South Africa – through a parliamentary process – established a regulatory authority as a juristic person in terms of National Energy Regulator Act, 2004, section 3 to regulate the entire energy industry. The Electricity Regulation Act, 2006, section 4 (ii) provides for the Energy Regulator to regulate electricity prices and tariffs.

Historically, South African municipal power utilities have placed emphasis on electricity sales as the basis of their tariff structures. These tariffs were also designed in accordance with the guidelines provided by the regulator. However, individual customers are becoming more efficient in their electricity consumption, thus resulting in reduced electricity sales. Sales of grid electricity are also rapidly dropping with the increasing adoption of PV technology, which is increasing penetration of distributed generation, thus negatively impacting on municipal revenues and pushing municipal power utilities towards the risk of unviability.

Garcez (2017) notes that distributed rooftop PV generation can also be referred to as decentralised or localised generation and is becoming an essential component of the business models of innovative power utilities. This significantly contrasts with the conventionally large and centralised generation systems that have been commonly followed by utilities till now. It is therefore evident that there is an energy transition from the conventional centralised to a hybrid system which entails decentralised energy generation especially driven by responses to supply-side constraints affecting Eskom. The transition which affects all power utilities, including municipalities, calls for a further transformation of the business models of municipal utilities in order to address the revenue impact in line with the global trajectory. The changing landscape from the conventional centralised electricity generation/supply model is further accelerated by the global imperative to mitigate climate change, as well as the rising electricity tariffs compared to the declining costs of PV systems when benchmarked on LCOE basis (Korsten et al., 2014).

The Constitution of the Republic of South Africa, (Act 108 of 1996) places the responsibility of provisioning of basic services on municipalities. These basic services enshrined in the constitution include provisioning of electricity in order for municipal utilities to deliver electricity, they operate under electricity distribution licenses issued by the NERSA section 6 of the Electricity Act

(Electricity Act, 41 of 1987: 6). The current business model for most municipal authorities is structured around derivation of revenues from the services they provide to their residents and complemented by an equitable-share they receive from the national government. Their revenue-generating streams includes property rates and taxes, water and electricity sales, as well as solid waste management levies among other licensing/services fees. Given that electricity sales constitute a significant component of the revenue stream for the municipalities, the increasing volume of PV penetration and self-generation might risk disrupting the current municipal business models, specifically on revenue earned from the distribution of electricity. When consumers generate their own electricity instead of purchasing from their municipal utilities, they reduce their dependence on the utilities, thus contributing to declining sales and revenue.

The increasing renewable energy penetration therefore requires utilities to conceptualise new business models around generating, delivering and the selling of electricity. The most common proposal by many proponents on the utility's side is the ownership of electricity generation asset (to mitigate cost-escalation on bulk purchasing) because of the large returns on investments such assets offer. In South Africa, current legislation allows municipal utilities to own generation assets of up to a certain capacity. However, exceeding the set capacity threshold requires cumbersome licensing procedures. Richter (2012) thus suggests that utilities need to move from operating primarily as providers of a commodity to providers of energy services based on the delivery of comprehensive energy solutions for their customers. This creates opportunities for new revenue sources which could be based on smart-grids, energy efficiency, and demand-side management. Utilities can also investigate the possibilities of venturing into provision of renewable energy technology systems such as PV systems to customers resident within their licensed area of supply.

2.2.2 Breakdown of the Business Models

Richter (2012) describes two distinct business models where the first focuses on the utility's side, while the second is mainly anchored on the customer's side (see Figure 2.3).

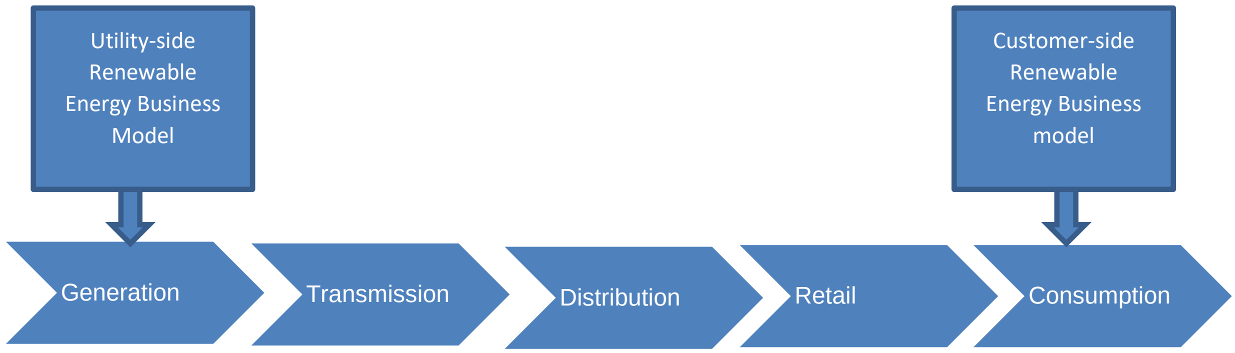

Figure 2.3: Electricity value chain showing utility-side and customer side business model opportunity (Source: Richter, 2012 page 2487).

On the utility's side, the value proposition is the feeding-in of electricity to the grid, which is delivered to the customer at a fixed price per unit. In the conventional value proposition, electricity is generated from fossil fuel, while in the new model generation becomes more environmentally friendly and, as a result, utilities offer a green tariff for "eco-power". Currently, there is international pressure on utilities to generate green power and reduce GHG emissions.

The customer interface is in the form of a power purchase agreement (PPA) on a business to business scale. This is because the transmitter would be different from the generator (in reference to the value chain) and the generator does not supply directly to the customer. Richter (2012) notes that the customer interface has three elements: customer relationships, customer segments and channels. Infrastructure entails the key processes and resources required to create the value proposition and would thus include generation assets. Revenue is derived from the regulated feed-in-tariffs. On the customer-side business model, the value proposition is the revenue generated from alternative customer services, such as consulting, financing, ownership and operation of the electricity asset located on the premises of the customer. Utilities need to be providers of comprehensive energy solutions beyond the meter, as demonstrated by the New Jersey public utility, which has a program for the provision of solar loans, where repayment of the loans, unlike with conventional banks, is not done in cash but in energy certificates (Richter, 2012). A single certificate is equivalent to 1000 kWh generated and is tradeable. Richter (2012) notes that additional benefits of this diversification of energy services are that the advertising, administration and meter installation are considered regulatory assets and included in the rate base order to earn a return. The utility, therefore, takes over the burden of capital costs of the generation system from the premises owner. Given that stand-alone individual services lack scale and are not profitable enough, service packages are deemed to be more profitable. Infrastructure relates to the internal architecture and would thus comprise of all assets required for the generation and delivery of the packaged value proposition. Customer interface or relation is intensified by the financing and ownership of the asset.

Under this model, the revenue can be collected from the return on the assets (now under the ownership of the utility), services on installation and operation of the assets, administration and management of the asset. As defined earlier, the revenue model refers to all the revenue and costs associated with the delivery of the value proposition. To date, most utilities' revenues are based on fixed price per kWh, which means that the utility profits are more when more electricity units are consumed and vice versa (Richter, 2012). This model creates disincentives for utilities to engage in energy efficiency initiatives and third-party energy generation because such initiatives would negatively impact the utility's revenue streams. This problem can be addressed through innovative changes to the business model to allow for responsive elements, such as decoupling, dynamic pricing and flat-rate tariffs, as appraised in detail below.

The collection of revenue by utilities is based on the implementation of rate structures or tariffs. Some rate "designs aggravate financial risks on utilities when sales decline", especially when the rate design links the revenue to sales volume (Costello and Hemphill 2014, page 14). The challenges of linking sales-volume to revenue have long been known and initial responses were presented to the Public Utilities Commission of California as far back as 1981 (Xue et al., 2014), where the key response was the decoupling of revenue from sales. Since this initial dissemination among public utilities, it is only recently that decoupling has started to be seriously considered as an opportunity for insulating the revenue of a utility from the fluctuations of sales based on breaking the link between the two (Eto et al*.,* 1997). The method thus ensures that utilities achieve their goal of revenue stabilisation independently from the volume of units sold.

The adoption of distributed PV generation and other initiatives, such as demand-side management (DSM) and energy efficiency on the customer side, also have a negative impact on the utility revenue. This is because they reduce customers' consumption from the utility's grid. The determination of the resultant value lost is, however, a challenge. Many regulators globally apply the rate of return methodology in regulating utility revenue, but this method has the unintended effect of disincentivising energy efficiency, DSM, and investment in distributed PV generation. The net income of a utility is the difference between the revenue collected and the costs incurred in providing the electricity. This can also be presented as a percentage of the total revenue.

The main purpose of decoupling in this context is to stabilise revenue recovery in a manner that compensates for the revenue lost through PV distributed generation and other programs, such as DSM and energy efficiency. Xu et al. (2014) note that successful implementation of decoupling requires two key components which are the targeted requirement and the amount of revenue collected under base rates. Revenue lost from distributed electricity resources (DER) can also be recovered from non-DER customers through other channels/streams, such as rates and taxes. This type of lost-revenue recovery tends to drive up the prices for customers not participating in distributed generation, and as a result, more customers are likely to opt to participate. Ultimately this results in additional loss of revenue to the extent where only an unsustainable number of customers which further makes the case on the critical significance of rate design.

Various cost structures can be created using different methods, such as dynamic pricing or flat-rate tariffs. These cost structures are the source of revenue for the utility. Richter (2012) defines dynamic pricing as a structure that is not fixed per kWh, but instead, the utility applies a price based on wholesale prices and can be real-time. Time-of-use (ToU) tariffs are examples of moderate dynamic pricing structures. These kinds of pricing strategies provide signals to customers when the price of electricity is high and when it is low. However, this model requires significant investments in smart grid technologies to provide utilities and customers with accurate and relevant real-time data while also facilitating customer choice-options. The method also involves a utility charging the same rate irrespective of the level of consumption as it does not normally penalise overconsumption or incentivise energy efficiency. It would, therefore, not be preferred as it fails to systematically allocate costs, especially in relation to generation-peaks, which are much more expensive to cover (Fridgen et al., 2018).

2.2.3 Cost of Supply (CoS)

As part of the current tariff application process, NERSA requires municipalities to conduct Cost of Supply (CoS) studies in accordance with its CoS framework (NERSA, 2017). What is important for this study is to note that, according to NERSA (2014), the following costs (amongst others) are regarded as non-applicable expenditure and are excluded from the operational expenditure costing:

- All streetlight and traffic light expenditure
- Energy costs paid to Eskom for lighting and other municipal buildings supplied by Eskom

CoE has conducted a CoS study as required by NERSA, where the key data are the costs associated with the calculation of CoS at the municipal utility level, which covers the following variables: P1 = the purchase costs from the grid, P2 = cost of technical and non-technical losses, P3 = profit margin, P4 = costs associated with assets used in the delivery of electricity, and P5 = costs associated with the manpower.

The London School of Public Affairs recommended “Bonbright’s seven principles of rate design as fundamental criteria for framing business outlooks” (University of Texas, 2017: page 8. The principles are as following:

- Designed rates should be understandable to the general public
- Must not be controversial and should be easy to apply without resistance from customers
- Must be highly effective in compensating sellers and encourage continued production
- Must provide predictability for budgeting purposes for both seller and customers
- Must be fair and consider customer’s distance from the source
- Non-discriminatory to any customer or group for whatever reason
- Should promote efficiency while discouraging wastages

NERSA’s Cost of Supply (CoS) is a fundamental methodology that is currently used to determine the true cost of service to electricity customers within the licensed supply area of a municipal utility (NERSA, 2017: page 5). After determining the cost of supply, tariffs are then developed based on the objective of collecting adequate revenue to cover the calculated costs and ensuring reasonable returns on investment. The main aim is to determine the full cost of supplying electricity to the different customer categories with the ultimate goal of appropriate rate setting. Figure 2.4 shows the process from CoS towards rate design with cost functionalization, cost classification and cost allocation processes as the key steps. University of Texas (2017) argues that although this methodology generally complies with the Bonbright principles it however does not promote efficiency.

In determining the revenue requirement (Figure 2.4), NERSA requires utilities to conduct CoS studies in compliance with the National Rationalized User Specification (NRS058). In determining CoS, the location of a customer in the network is important (NERSA, 2017). However, it is not practical to model costs of an entire network with an individual customer as the reference, hence the need to group customers into categories. A reduced network diagram (RND) can be created by pooling customers in terms of voltage levels and asset type (CoE, 2018). Customers connected at higher voltage levels do not utilise the same networks which supply customers connected at lower voltage levels. They should not be allocated the additional costs associated with networks at lower voltage levels. This can be translated to the principle that customers who do not utilise an asset availed to the market by the utility should not be burdened with related cost as part of the costs-recovery pricing model.

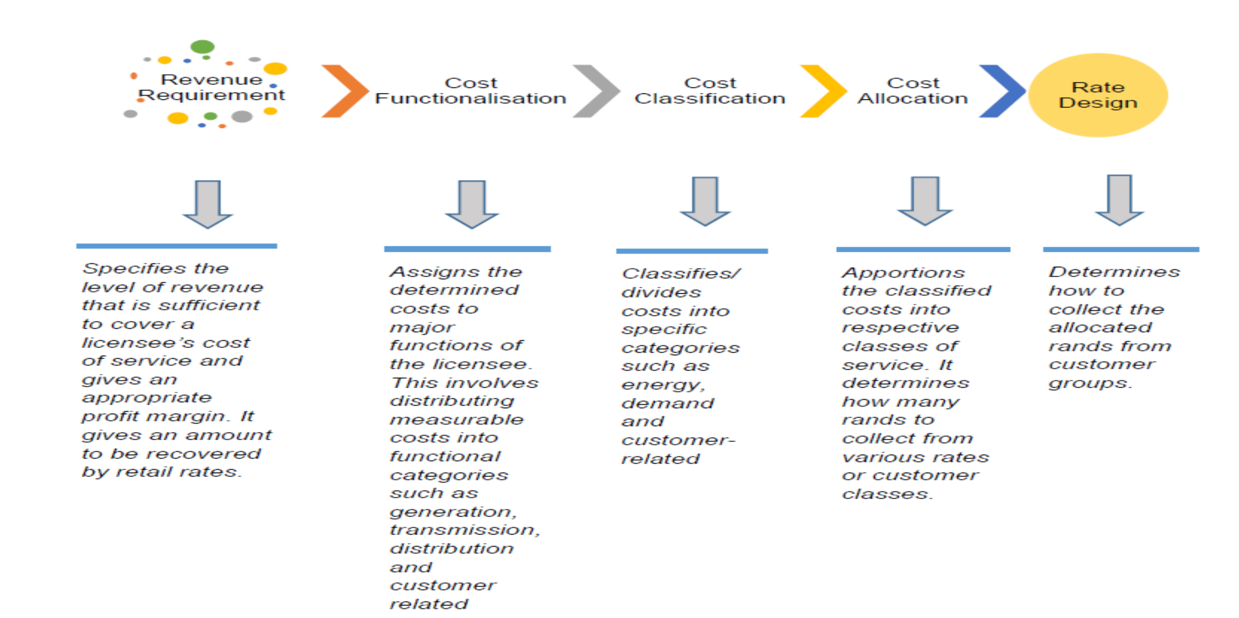

Figure 2.4: CoS steps (NERSA, 2017 page 6).

CoS is defined by the formula below, which includes the applicable costs as listed:

$$Total\ CoS = \sum_{k=1}^{n} P_k$$

where CoS is the cost of supply and P represents all applicable costs. In the case of CoE, these costs start with the purchase costs of electricity from Eskom as the supplier. By adding all the additional costs incurred in the process of distributing electricity to the consumer plus fair profit, the culminating figure gives the cost of supply or CoS for the respective utility. The CoS is translated into the revenue requirement that a utility must collect for it to remain viable (NERSA, 2017). Given that municipal power utilities collect revenues from their customers using rate structures that are approved by NERSA, this motivates for the requirement to standardise the methodology of determining CoS. The profit margin allowable by NERSA currently range from 10% to 20% (NERSA, 2017). This margin ensures that the utility can recover its costs associated with the delivery of electricity. The formula also provides an opportunity for utility enhancing efficiencies as utilities can be financially incentivised by the regulator to become efficient (e.g., by minimising losses). For example, NERSA incentivises utilities for losses below 10% based on adjusting their allowable collectable revenue (NERSA, 2017).

The next step in the CoS process is cost functionalization, which is the arrangement of costs according to the functions of the utility, such as generation, transmission, distribution and retail. For municipal utilities in South Africa, the bigger portion of these costs will be allocated for distribution and retail with a smaller portion allocated for generation and in some cases transmission. The importance of allocating functional costs is to facilitate in determining customer categories or groups responsible for particular costs to arrive at more relevant/appropriate rates/tariffs.

The following are the key steps in cost classification based on cost functionalisation. Initial step entails the classification of costs into fixed or variable costs. Costs are then 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” (NERSA, 2017: 13). The cost classification is followed by cost allocation, where the fixed and variable costs are allocated to the different service classes. Once cost allocation is completed, the process of rate-setting is implemented. This entails the process of designing a rate-structure that will allow recovery of the cost of service as guided by the established revenue requirement.

2.2.4 Tariff Design Approaches

Tariff design and cost of supply are some of the concepts featured in the process of conceptualising a business model incorporating distributed generation. Ongoing and systematic integration of distributed PV generation would bring additional network costs, that must be recovered by the network operator through an appropriate tariff design. The cost of providing service to the different users is, however, not the same (Picciariello et al., 2015). Therefore, the resultant electricity tariffs (also called distribution use of system charges DUoS) contain the following elements:

- Fixed charges covering the cost of keeping the user connected to the grid;
- The volumetric charge, which is an energy charge aimed at covering the costs of variables associated with the delivery of electricity;
- A capacity charge, also known as a demand charge, which is based on the agreed capacity or, as in some cases, the maximum capacity used within a specified time-period (Picciariello et al., 2015).

Municipal power utility costs are generally classified as fixed and variable costs. Fixed costs do not fluctuate with the volumetric change in sales (although they might fluctuate when evaluated over very long periods) whereas variable costs do. The integration of distributed PV generation requires a proper tariff structure which includes some or all the three components mentioned above. In addition to a proper tariff structure, variations to a tariff that includes time-of-use might also be explored. There are various methods of recovering fixed charges, such as through implementation of demand charges, time of use rates, block rates, revenue decoupling, lost revenue adjustment mechanisms, and formula rates, amongst others (University of Texas, 2017).

One of the criteria applied in designing tariffs is the cost-causality principle, which requires that the tariff structure be set in a manner that is reflective of capital and operational expenditure caused by the connection of a customer to the network (Picciariello et al., 2015). This is not a simple process as it might be difficult to track all the associated costs. As a result, the process is simplified by grouping customers together into categories to which the cost-causality factors are then applied. This methodology would thus require the calculation of network costs associated with each PV scenario and "to identify load driven and PV driven costs" (Picciariello *et al*., 2015:25). The next step would be to calculate network tariffs and after that, assess the tariff approach. Most utilities, including CoE, have designed their electricity rates such that they recover a large portion of their fixed costs from the volumetric charge or quantity in kWh. This is only sustainable when consumption patterns remain within or exceed the expected levels. A decline in the quantity of the kWh would thus present a problem to the utility as the revenue decreases, even though most of the costs are likely to remain unchanged.

Below is a simple formula that for determining a customer's account using a two-part tariff base rate:

$TB = \alpha F + Q\,[(1-\alpha)\,F/Qty + v]$ (Costello, 2014:14)

TB illustrates the total account, F represents the utility's fixed costs allocated to the customer, **Q** represents the actual sales, Qty represents the test year sales, **v** represents the utility's variable costs allocated to the customer, and **α** represents the portion of the utility's fixed costs that are recovered in the fixed charge. By recovering a larger portion of the fixed costs from the volumetric charge (lower **α**), a utility is now exposed to higher revenue fluctuations when the sales either increase or decrease. This means a stronger incentive exists when the sales increase and a utility suffer losses when the sales decrease. It is, therefore, important to design a tariff that takes into consideration all these possibilities and still be able to recover the costs to ensure the sustainability of the utility's operations.

2.2.5 Mapping the current municipal business model using BMC

This study ultimately aims to conceptualise a responsive business model for municipal power utilities. It is thus important to understand the current/status-quo in the value chain and the existing business models as they are key factors that would inform the responsive business model. It is therefore necessary to understand the existing business model for municipal power utilities in South Africa in order to respond to the challenges posed by the current transition, and to assist in formulating a responsive and innovative business model. The BMC is applied to map the existing current municipal power utility business model as shown in Table 2.3.

<table>
<tr>
<td rowspan="2"><u>Key Partners</u>:

Eskom SOC

● Internet service providers
● Third-party vendors/retailers
● OEMs
● Service Providers/ESCos</td>
<td><u>Key Activities</u>:

Procure electricity.

● Operate & maintain an electricity distribution network.
● Resell electricity</td>
<td rowspan="2"><u>Value Proposition</u>:

● Provide electricit y in the licensed area</td>
<td><u>Customer Relationships</u>:

● Municipal power utility licensed to distribute electricity
● Regulatory environment provides for no competition
● Customer information programs, adverts</td>
<td rowspan="2"><u>Customer Segments:</u>

● Residential customers
● Industrial customers; and
● Commercial customers</td>
</tr>
<tr>
<td><u>Key Resources</u>

CoE owned distribution network

● Vehicles
● Human resources
● Finances</td>
<td><u>Channels</u>:

Municipally owned electricity distribution network provides physical delivery

● Post-paid (billing)
● Pre-paid-kiosks for tokens, online token purchases
● Face-to-face purchase of tokens</td>
</tr>
<tr>
<td colspan="3"><u>Cost Structure</u>:

Electricity purchases

● Maintenance costs
● Operational cost
● Free 100 kWh to the different customer</td>
<td colspan="2"><u>Revenue Streams:</u>

● Segments based on consumption
● Different Tariffs structures for different customers and size of connection exist</td>
</tr>
</table>

Table 2.3: The current municipal power utility business model mapped using the BMC (adopted from Osterwalder and Pigneur, 2010).

The current business model for CoE involves procurement of their electricity supplies from Eskom generation. Municipal utilities currently own and operate conventional grids that are inefficient due to ageing infrastructure. Currently, grids do not incorporate any smart components or capabilities and heavily rely on manual operations. In as much as customers can generate and export surplus electricity to the grid, they are not compensated by the utility for this electricity. The revenue collection methods of municipal power utilities are based on tariff structures that couple revenue to electricity sales, where meter readings are performed manually without the use of remote systems. This creates the potential for errors and other efficiency-related issues. The management of non-technical losses as well as other operational efficiencies is of additional concern. Every kWh purchased and not delivered to a paying customer has negative financial implications for the utility.

2.2.6 Innovations in utilities' business models

The ongoing changes in the electricity distribution sector has forced the industry to design innovative concepts to address related negative impacts on the business models of distribution utilities. The innovations are aimed at addressing the increased complexities introduced by the changes, such as easing the barriers to distributed PV generation (Horvath., D and Szabo., R, 2018).

Germany experienced an ongoing increase in PV-generated electricity with most of it coming from rooftops of residential buildings. By the end of 2011, Germany had an installed PV capacity of 25,000 MW (Richter, 2013). By the first quarter of 2012, Germany was already generating 25% of her energy from renewable sources, and 5.3% of this was from PV (*ibid*.). This trend presented Germany with both threats and opportunities. For example, it opened opportunities for communities to access cheaper electricity due to low LCOE of PV while also forcing utilities to innovate into new business models to accommodate the transition, and therefore protect their revenues while attracting infrastructure investment (Richter, 2012).

On the other hand, the development of rooftop PV threatened existing organisational structures and business models. There was fear that this could lead to a massive loss of market share, revenues and profits (Richter, 2013). For utilities to properly address the threats posed by increased distributed PV penetration, they needed to perceive PV as an opportunity rather than competition to their conventional energy sources. In their effort to adapt to this transition, German-utilities used a model that involved accepting power from independent power producers (IPP) meaning that the IPPs did not only generate for their own consumption but also for selling surplus to the grid.

Germany used multiple incentives to encourage distributed generation. Consumers were thus encouraged to consume electricity closer to where it is generated and only feed the surplus into the grid. Consumption beyond what consumers could generate was met from the grid at the same time. This meant that they had to continue being connected to the grid. Richter (2013) notes that during this transition, utility officials interviewed were not excited about distributed PV generation and neither did they perceive distributed PV as a threat to their current business model, as an opportunity for future business development. Utilities benefit greatly by adapting to new technologies and not treating them merely as competitors to conventional technologies, but as a way of entering a new era of new business models for utilities (Richter, 2013).

Similar studies were also done on the US experience. This includes Millar and Patiño-Echeverri (2013), who conducted research on the decoupling of revenue from electricity sales. Implementing such a model suggested that a decoupling approach would, however, require regulatory approval in a regulated environment. The decoupling of revenue from sales model, "insulates the risk of under-collecting revenue for any reason such as aggressive efforts to reduce consumption through efficiency, conservation, or DG" (Millar and Patiño-Echeverri, 2013:8).

The study further highlighted three existing mechanisms of decoupling sales from revenue. The first one is achieved by charging a fixed fee per customer based on the overall cost of service. The first method further requires that the cost of volumetric sales be added to the fixed fee to recoup operational costs in addition to the cost of power purchased. The second method is called the Lost Revenue Mechanisms, and the third is the revenue-per-customer decoupling. The lost revenue recovery mechanism (LRAM) allows the utility to recover the cost incurred due to the implementation of energy efficiency by reimbursing the utility based on the estimated cost of energy efficiency. This method is riddled with problems of monitoring and evaluation requirements. On the other hand, the revenue-per-customer decoupling (RPC) method links the recovery of revenue to customer-growth instead of volumetric sales. It also allows for the rate to be adjusted automatically at certain regular intervals. It is accepted that customer growth is less variable when compared to sales. Sales are sensitive to weather, adoption of distributed generation and energy efficiency interventions, among other factors.

On the other hand, Thailand has facilitated PV penetration by implementing feed-in-tariffs. Together with the ongoing decline in PV system costs, this has increased the adoption of the technology in the country (Tongsopit et al., 2016). Thailand initiated renewable energy (RE) policies in 2006 and have therefore evolved for over one decade. The first implementation of the policies occurred in 2007 with a FiT called adder scheme. This scheme was a modified FiT, which incentivised RE producers by allowing them to sell their electricity at a utility rate plus an adder rate (also known as premium-price FiT). This incentive was managed through 10-year Power Purchase Agreements (PPAs). The adder scheme was later discontinued in 2010 because of concerns on the impacts on ratepayer taxes and replaced by the fixed-price FiT in 2013. This fixed-price FiT scheme was aimed at supporting rooftop solar installations and the initial total quota was 200 MW. By 2014, Thailand's RE installed capacity was about 1354 MW, and most of it was from installations exceeding 1 MW. The low cost of solar systems and the rising costs of grid electricity also contributed to this achievement. Net-metering was also later introduced to replace quotas. This net-metering scheme allows for the generation of one's own consumption first and then exporting of surplus electricity to the grid at retail rates.

In Brazil, the restructuring of the electricity sector in 1996 prioritised the objective of introducing competitive markets under the oversight of an energy regulator, whose mandate entails "regulating generation, transmission, distribution and commercialisation of electricity in Brazil'' (Garcez, 2017: page 107). The country has since implemented multiple restructuring initiatives in the electricity sector over the years. In 2012, a resolution by the National Energy Regulation Agency was passed to create a new class of generators/consumers. This resolution covered distributed mini- and micro-generation as the targets for implementation of net-metering focusing on hydropower, solar, wind, biomass or cogeneration as the primary sources of energy. The passing of the resolution required the development of the corresponding net-metering standard, which eliminated the "cumbersome need to register as an energy participant" (Garcez, 2017 page 107). The study notes that the successful implementation of distributed generation requires long-term energy planning, as well as a comprehensive legal framework. The micro-generation and mini-generation opportunities incentivised by Brazil's policy on distributed generation is categorized into three categories: equal-to-or-less-than 100 kW, greater-than 100 kW, and equal-to, but-not-more-than 1 MW.

The Brazilian policy does not incentivise distributed generation because the permitted sizes of projects are limited to the quantity of electricity consumed within customer operations (Garcez, 2017). It is therefore argued that this feature in the Brazilian policy, in fact, hinders the uptake of distributed generation. However, the net-metering policy ensures that any surplus electricity that flows into the grid is credited to the bill of the project owner. Net-metering (as opposed to Feed-

In-Tariff) allows grid-connected customers to receive credit units instead of financial compensation. In implementing distributed generation, Garcez (2017) emphasises the need to ensure a simple and streamlined process aimed at reducing transaction costs related to distributed generation. Brazil's case demonstrates the option where distributed generation is facilitated through two-way energy flows as part of the country's national smart grid applications.

Krupa and Burch (2011b) argued that the renewable energy sub-sector remains a contested topic in South Africa. This is due to the nature and architecture of the energy sector in the country, which has already been criticized for "inappropriate politicisation". The state-owned utility, Eskom, has controlling interests in all aspects of the electricity value-chain *(ibid)*. Even though there are various renewable energy policies, they show a deficiency on critical issues, such as micro-financing schemes for low-income communities, direct government investments, development of green power market, and manufacturing clusters focused on renewable energy technologies (Krupa and Burch, 2011b).

South Africa has also implemented a feed-in-tariff program with Eskom as a single buyer, which thus exclude municipalities from transacting directly with the independent power producers within the large utility-scale renewable energy generation. The possible involvement of municipalities in transacting directly with IPPs can only be realized with permission from the Minister of Energy, through a ministerial determination for systems that are above the allowed threshold of 1 MW. This implies that there is provision for participation of municipalities to transact with small-scale, embedded generators within the prescripts of the Municipal Finance Management Act (MFMA). However, municipal utilities in South Africa are not proactively taking up this opportunity. The regulatory environment in South Africa, therefore, requires further enabling policy framework (similar to that of Brazil or Thailand) to further stimulate the penetration of SSEGs.

2.3 The impact of distributed PV generation on the current municipal business model

South Africa is considered to be among the countries with a high potential for solar energy globally based on its high levels of solar radiation of between 4.5 to 6.6 kWh/m² per day (Jain and Jain, 2017). The abundance of this renewable energy resource (together with the evolving enabling-legislation) presents an opportunity to reduce current dependence on fossil fuels and the associated impact on climate change and global warming from high levels of greenhouse gas emissions (GHG).

Municipal power utilities in South Africa purchase almost all of their electricity from Eskom at bulk prices and then distribute to consumers at a margin to generate revenue to cover the cost of operation and maintenance of the infrastructure for the service, as well as cross-subsidising other municipal services for their residents. However, Eskom electricity prices have been on an upward trend and increasing at above-inflation rates annually with no indication of slowing down anytime soon due to, amongst other things, additional costs from poor management practices, inefficient infrastructure and costly debt. In addition, due to the declining cost of PV systems, a growing number of consumers are opting to implement distributed PV systems (on their roofs and on-site open spaces, such as car parks) as a means of mitigating the escalating costs of grid-supplied electricity. This trend is mainly noticeable within the medium to high income residential suburbs, as well as by industrial and commercial sector consumers.

Insights from several studies further indicate that this shift from conventional grid electricity and related dependency on municipal distribution are translating to a negative impact on electricity-related revenue for municipal utilities. The two studies identified for review in this section are based on the case studies of the City of Cape Town and Stellenbosch municipal distributors, with a focus on distributed PV systems installed by residential consumers. The Cape Town study investigated the impact of the increased PV penetration on municipal revenue over 15 years, from 2015 to 2030 (Mayr et al., 2015).

Similar to all municipal authorities in South Africa, the City of Cape Town is responsible for the design of the different tariffs for consumers within its licensed area of supply. The tariff design is mainly informed by consumption levels and indigent status of the resident-customers. The City of Cape Town collects about 35% of its total budgeted revenue from electricity revenue (Mayr et al., 2015) and this is the largest share out of all the revenue streams for the City. Residential customers contribute 40% of the total revenue collection. Similar to other cities, Cape Town is experiencing an increased penetration of distributed PV as a result of the declining costs of PV technology, and the increasing electricity rates against the increasing risk of unreliability of grid supply. This increase in self-generation by consumers is leading to the erosion of electricity revenue for the municipality and might result in an adverse gap between the revenue collected and the related electricity- distribution costs.

In conducting the study on the impact of PV on municipal revenue, Mayr et al. (2015) divided the city's 570,000 customers into groups according to consumption levels and socioeconomic status, with the first group being the subsidised poor. After that, hourly load profiles were assigned to each group based on measured profiles. The electricity bill was then minimized for each profile by considering the possible effect of investing in a PV system and battery storage. Mayr et al. *(*2015) applied this methodology for a period spanning 15 years (from 2015–2030), with the tariff structure being kept constant and using the average electricity bill for each group (see Figure 2.2 for an illustration of the methodology used in the study).

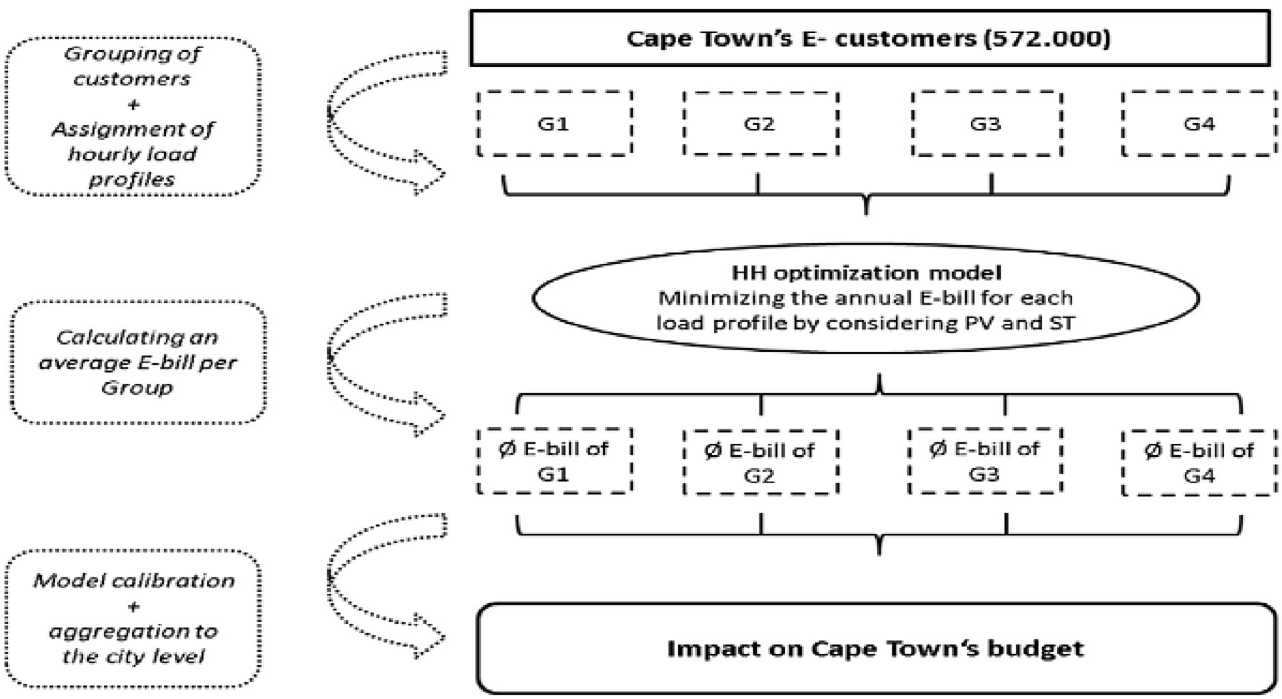

Figure 2.5: Methodology for assessing residential PV impact on municipal revenues (Mayr et al., 2015, page 13).

The study concluded that as the distributed PV penetration increases, the City of Cape Town would be negatively impacted should it continue with its business-as-usual model. The study, therefore, recommended the introduction of a revenue-neutral fixed network-connection fee to mitigate the negative impact of distributed PV on municipal revenue. The evidence demonstrated that, due to the cost-effectiveness threshold, low-income households are, however, unlikely to implement distributed PV systems and, therefore, likely to continue depending on the centralised distribution (Mayr et al., 2015). This would be highly detrimental to the City as the consumer group contributing most to the revenue is likely to opt for own generation as the cost of power increases, leaving the City with a burden of mostly supplying to the subsidised/poor segment of the residents.

The second study by Korsten et al. (2017) focused on the Stellenbosch Municipality and argued that distributed PV should be understood as a disruptive technology in a conventionally centralised energy system that is thus being transformed into a more decentralised structure. The study further notes that the municipality collects 30% of its revenue from the distribution of electricity for its customers, which suggests that the ongoing transition would eventually lead to a reduction in municipal revenue while related overheads are likely to remain the same or even escalate. The study, therefore, recommends that, with the increase in “prosumers”, there is a need to revise the current municipal business model to ensure that the utility remains viable. Noting that when sales decrease, the utility costs do not necessarily decrease, the study concludes that the utility would face the risk of unrecoverable high fixed costs associated with investments in the distribution unit/infrastructure/service over time. The recovery of the utility’s fixed costs would, therefore, be at risk when the kWh sales decrease. The power utility is likely to respond by increasing the tariffs to compensate for the declining volumes. Such a response, in turn, poses a risk of inducing a death spiral (where even more consumers become incentivised to switch to alternative electricity sources that would then be at a lower cost compared to grid-supplied electricity, thus leading to further escalation of unviable business risk for the utility). Figure 2.6 shows a general costs recovery model:

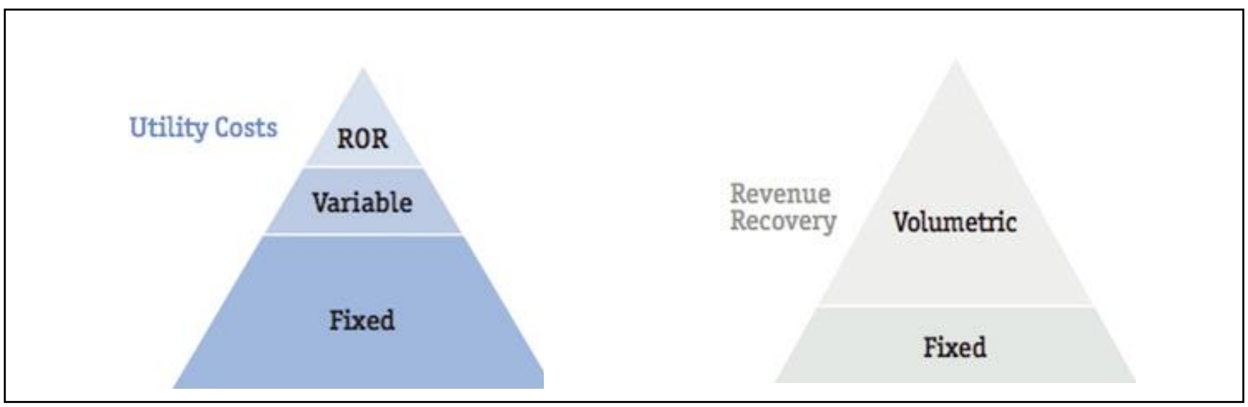

Figure 2.6: Utility’s allowed revenue and recovery model (Korsten et al., 2017, page 31).

Korsten et al. (2017) took a different approach from Mayr et al. (2015) by focusing first on establishing grid capacity (maximum distributed generation capacity that a grid can accommodate before any grid studies are needed). Eskom (2014) provides guidelines on how to determine grid capacity and model future scenarios under distributed PV. To determine the maximum grid capacity, Eskom (2014) recommends utilisation of 15% of the MV cables capacity of each area and a maximum of 25% of the transformer capacity at low voltage (Eskom, 2014 page 6).

The second approach suggested by Korsten et al. (2017) involves an investigation on the customer groups most likely to install PV systems over time. The key assumption of the study is that this would be financially feasible mainly for customers with high electricity consumption, possibly around the threshold of 600kWh per month. Korsten et al. (2017) use solar PV and municipal data collected for the municipality's financial year (instead of the calendar year) to create consistency with the tariffs. The maximum possible capacity that can be accommodated was then determined using a modelling software and the available secondary data as input. This was estimated to be just below 10% of the city's current Notified Maximum Demand (NMD). The difference between electricity revenue and expenditure is a critical factor in determining the impact of distributed PV on the operations/viability of a utility in general especially based on the principle that the revenue must always cover the expenditure.

As an option for mitigating the loss of electricity revenue, Korsten et al. (2017) suggest increasing rates and taxes this corroborating the findings of Mayr et al. (2015) on Cape Town, reporting that as distributed PV penetration increases the municipality will experience a drop in electricity sales. This loss will inevitably increase, and as it increases, the revenue collection will decrease if the respective municipalities continue with their business-as-usual models. The extent of this decline in revenue can be expected to be higher than what is reported in these studies because the studies only focused on high-income residential customers while excluding commercial and industrial customers who now continue to enter the market.

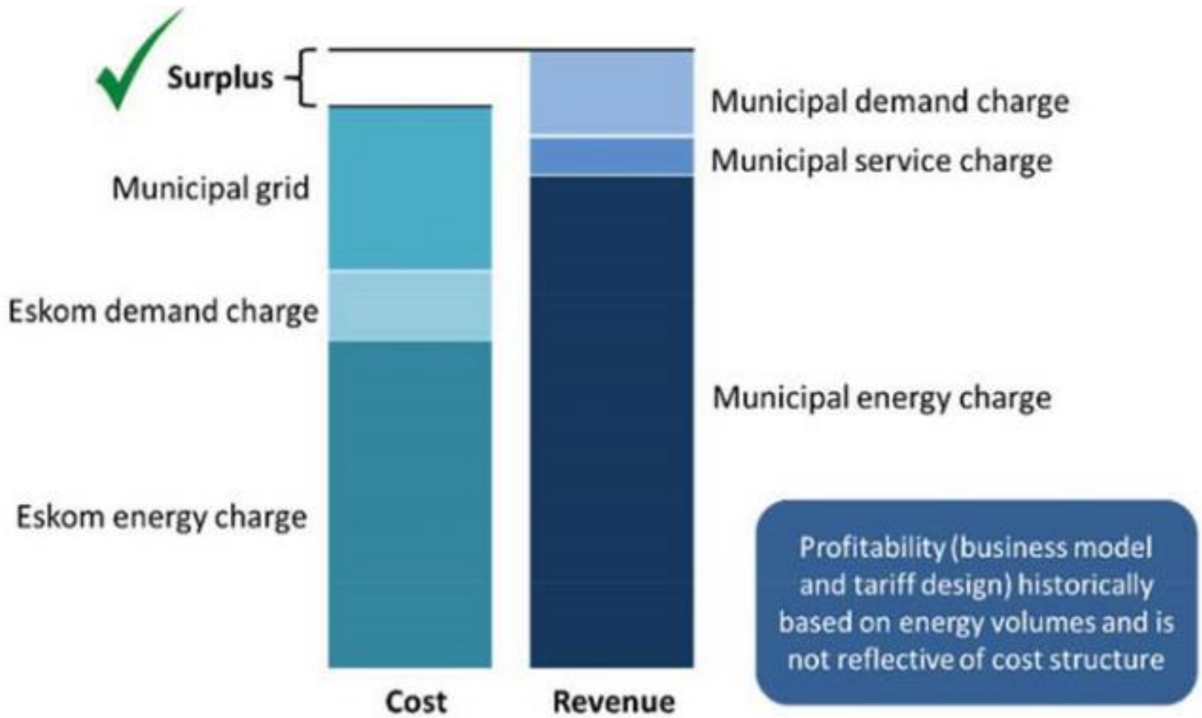

Figure 2.7: The current revenue collection apportionment: Eskom versus municipality (Source Lekoloane et al., 2018, page 4).

The current regulatory environment does not support cost reflectivity in tariffs. Currently, NERSA regulates municipal tariffs by way of benchmarking to Eskom, which is not an efficient utility by several measures. If we are to embrace new business models and want the new models to facilitate the viability of municipal utilities, the tariffs must be as cost reflective as possible.

2.4 Operational Efficiency Parameters

This section appraises studies on the important parameters related to operational efficiency. These are Energy Efficiency and Demand Side Management, Technical and non-technical losses, LCOE, and digitalisation.

2.4.1 Energy Efficiency and Demand Side Management

The demand and use of electricity are expected to continue growing due to such as factors as economic growth with resultant increase in commercial and industrial production, population growth (especially urbanisation rates), and increased access to electricity. For utilities to meet this demand, they need to ensure that the infrastructure is expanded and upgraded. They also need to maintain a healthy balance between supply and demand (Diawuo et al., 2018). The available options would be to either increase supply or reduce demand to address supply-demand imbalances. The increase of supply is the responsibility of the power utility, whereas the reduction of demand is mainly the responsibility of the consumers. Power utilities are also their own consumers as they also own and operate facilities/loads that are connected to the grid. As one of the options of reducing consumption, energy efficiency can be achieved through retrofitting of energy-efficient equipment or addressing human behaviour, such as the switching off equipment that is not in use. Implementing energy efficiency measures to address supply challenges helps utilities to minimise the need to build new power stations and other associated infrastructure, thereby mitigating the escalation of the critical costs associated with electricity supply. The capital costs of building new infrastructure are linked to the CoS, as demonstrated in Section 2.2.3, and these costs have to be recovered from the consumers.

2.4.2 Technical and Non-Technical Electricity Losses

Understanding energy losses is one of the critical elements towards improving the efficiency of a utility and this, in turn, affects the final price of electricity. Energy losses occur in any electrical network and encompass both technical and non-technical losses. Technical losses (TL) occur due to the dissipation of energy in the process of transmission or distribution through the network. In contrast, non-technical losses (NTL) are associated with non-billed or billed but not-paid-for electricity. NTL are more likely to arise at the consumer connection points. Non-billed energy can be as a result of metering and billing errors or illegal behaviour by consumers, such as illegal connections and by-passing the meter. To estimate non-technical losses, one must initially estimate the technical losses. The cost of non-technical losses is ultimately covered by the legitimate consumers. When quantifying the Cost of Supply (CoS), NTLs are added as one of the costs associated with the delivery of electricity to the consumers. Viegas et al. (2017) notes that for USA and UK, estimated yearly levels of NTLs due to theft are about US$6 billion and US$173 billion, respectively.

There are various ways of addressing NTLs, and some of these are technological (such as the deployment of smart grids). However, the detection of NTLs is crucial for the implementation of a responsive mitigation strategy. Viegas et al. (2017) identify the possible points of NTL vulnerability as follows:

- **Before meter**: This is where illegal tapping of distribution lines and feeders occur.

- **Within the meter:** The meter is another vulnerable piece of equipment that is prone to reversing, disconnecting and by-passing among other interferences.
- **Billing**: There are multiple possibilities in this zone for NTLs. such as inaccurate billing due to faulty equipment and employee error, non-payment of bills, collusion between customer and utility employees to arrange billing reductions and cyber-attacks on billing systems.

In the 2017/2018 financial year, South African municipal utilities suffered a loss of R9.2 billion through NTL (Bindeman, 2018). This was mainly as a result of illegal connections by unknown consumers, meter faults, meter tampering, data fraud and corruption. The national target for NTLs in South Africa is currently at 9%, and municipal utilities need to make provision for the required budget to fund revenue protection programs, such as appropriate metering infrastructure. Energy losses are a component of the CoS formula and thus have an impact on the total CoS. On the other hand, technical losses are excluded from the quantification of CoS. However, this does not mean that there is no further room for improving technical losses. One way of addressing technical losses is to ensure that network components are energy efficient. The overall impact of effective mitigation of technical losses is potential improvement in the profitability of the utility.

2.4.3 The Levelised Cost of Electricity (LCOE) of PV versus grid parity

PV technologies are maturing at different speeds and the feasibility of rooftop distributed generation is improving rapidly. This has been demonstrated by its declining levelised cost of electricity (LCOE) in comparison to other generation technologies (Branker et al. 2011). The two key parameters relevant to the assessment of LCOE are the lifecycle costs and energy production. LCOE is used as a “benchmarking tool to assess the cost-effectiveness of different energy generation technologies” (Ouyang and Lin, 2014). The importance of LCOE becomes evident when one starts to compare the LCOE trend for PV versus the utility (grid) prices over the same period.

Said et al. (2015: page 38) formulates a simple equation for deriving LCOE as follows:

$$LCOE\left(\frac{c}{kWh}\right) = \frac{Total\ Lifecycle\ Cost(\ for\ the\ technology)}{Total\ Lifetime\ Energy\ Production}$$

The following parameters are critical in the derivation of LCOE: discount rate, system costs, financing and incentives, system life for PV, the degradation rate and energy output. It is also important to note that utility prices differ from one customer class to the next, as well as from one delivery voltage level to the next. In many instances, however, conventional electricity prices continue to rise while PV LCOE continues to drop due to increasing scale-up in the adoption of the technologies in the market. Suppliers are thus able to benefit from economies of scale from increased demand and therefore able to sustain their business operations at lower prices. Nonetheless, “the actual electricity prices depend on the marginal cost of electricity generated by the given power plant and market-based or regulatory measures” (Said *et al.,* 2015).

LCOE can be derived with different evaluation tools, such as solar advisor model (SAM), EnergyPlan or RETScreen. As PV LCOE continues to decrease, and the grid tariffs continue to increase, the trends intersect at a point referred to as “grid parity condition” (Said et al., 2015). The point of intersection highlights the threshold of cost-effectiveness of the generating technology. Renewable energy costs in South Africa have declined dramatically with some technologies reaching a decline of around 80% over the four REIPP bidding windows (Calitz et al., 2017 page 3). The biggest cost decline is notable in wind and PV technologies, where the LCOE of PV dropped by more than 50% between 2010 and 2014. This makes PV a more competitive electricity generation technology at both residential and commercial markets as a result of dropping capital costs, improved capacity factors, economies of scale and increased conversion efficiencies (Stark et al., 2015). Stark et al. (2015) further present an analysis of the LCOE for PV and natural gas in multiple countries, such as China and the USA, which confirms the increasing cost-competitiveness for solar PV compared to natural gas (see Figure 2.8). The latest trends on the cost-reduction improvement trends for various renewable energy technologies show that renewable energy penetration has been increasing over the years, mainly due to improved economic competitiveness of the different technologies (Ralon, 2018).

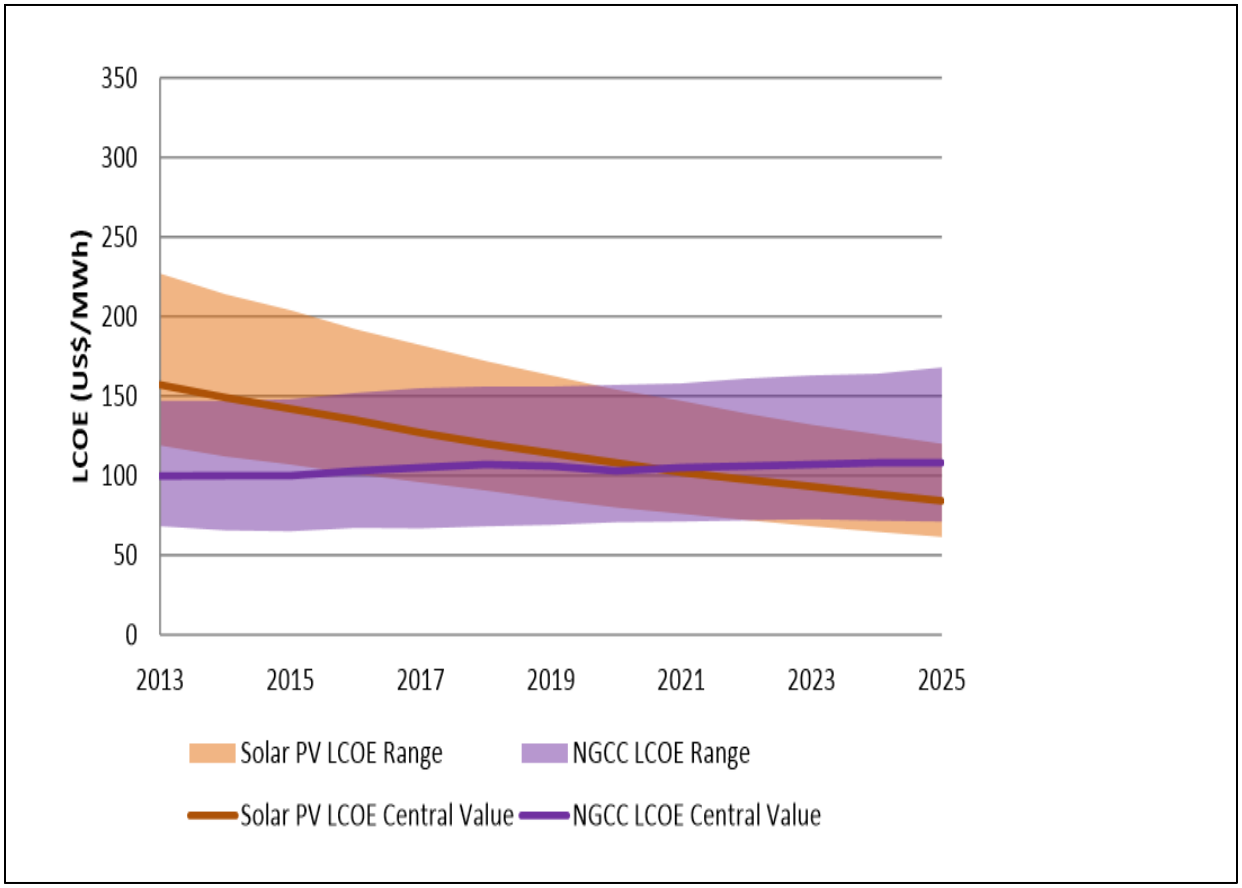

Figure 2.8: LCOE ranges for PV versus natural gas (Source: Stark et al., 2015 page 10).

The World Energy Council has also concluded studies on LCOE trends for different countries from 2006 to 2014. The results show a downward trend in PV LCOE in multiple countries. The report also noted that due to factors such as the difference in capital costs (especially on equipment and labour), and levels of solar irradiation resource, LCOE was different for each country covered in the study (WEC 2016: 29). In South Africa, for example, it was observed that the PV LCOE had fallen by 75% from R3.84/kWh in 2011 to R0.65/kWh in 2015 (see Figure 2.9).

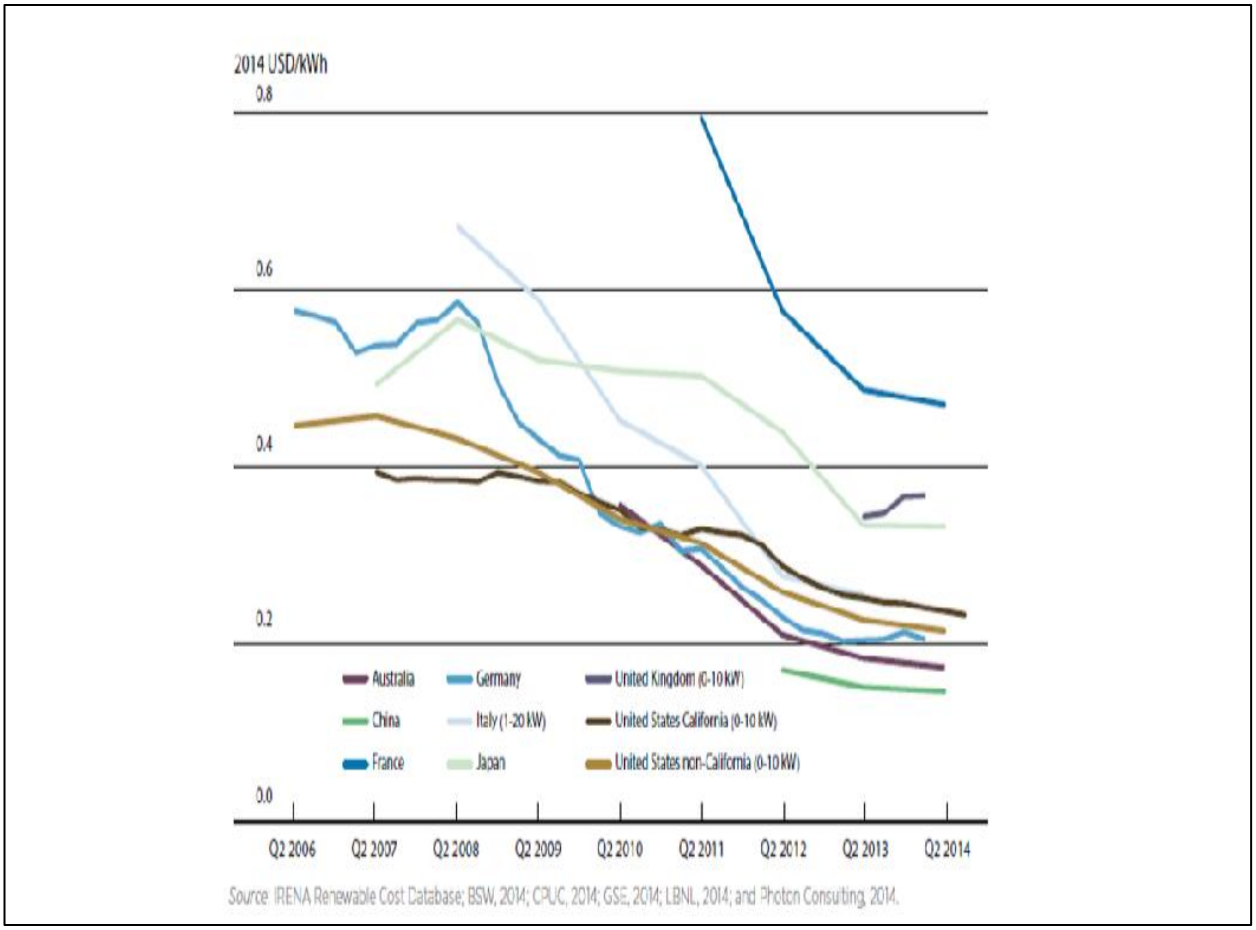

Figure 2.9: PV LCOE for various countries from 2006 to 2014 (WEC 2016, page 29)

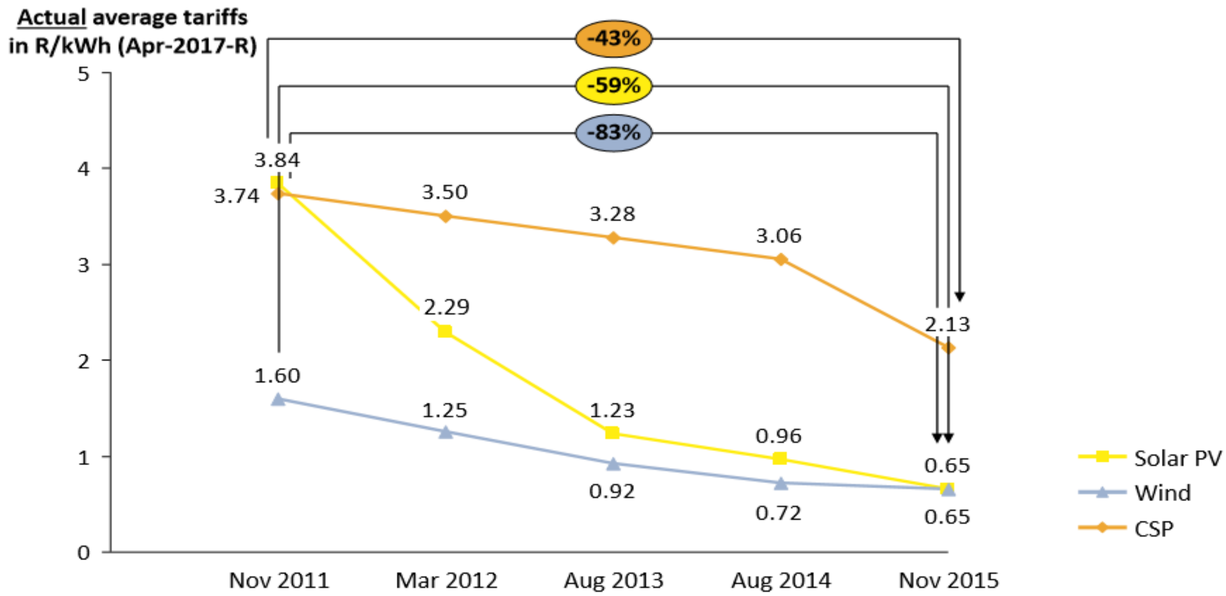

Figure 2.10: PV LCOE at R0.65 for South Africa by November 2015 (Calitz et al., 2017, page 7).

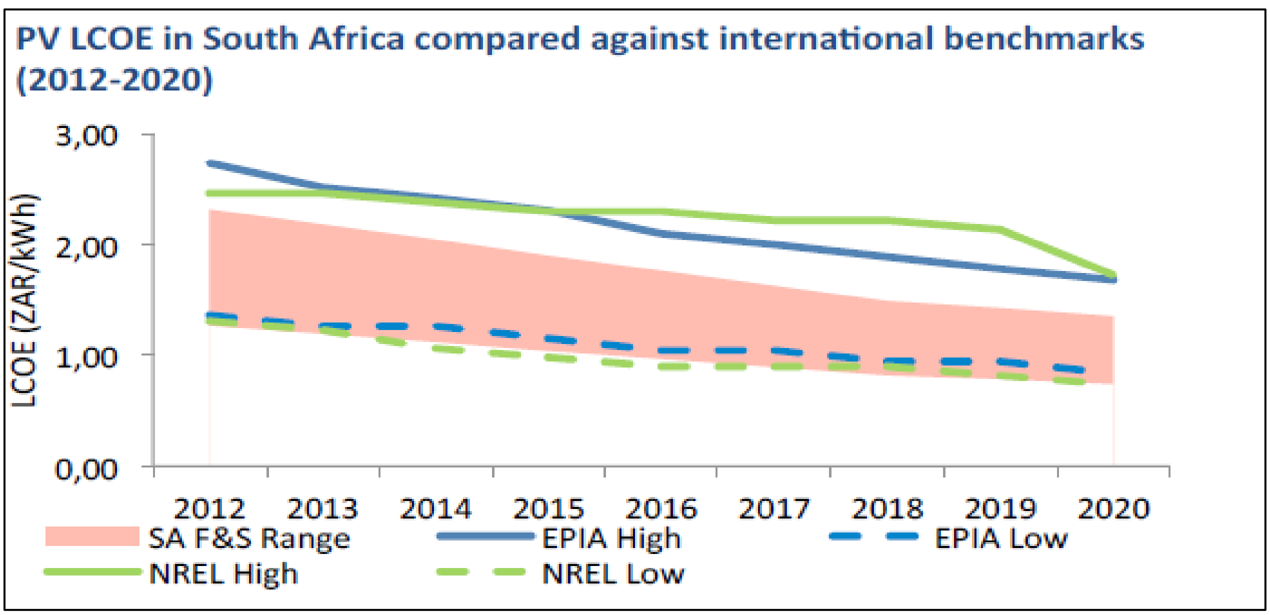

Figure 2.11: LCOE trend for South Africa from 2012 to 2020 versus international trends (Source: The South African Photovoltaic Industry Association (SAPVIA), 2013, page 30).

SA F&S Range refers to the South African Price Range; EPIA refers to the European Photovoltaic Industry Association; and NREL refers to the National Renewable Energy Laboratory

Figure 2.11 also shows the low and high ranges of the PV LCOE. The high range of the LCOE is as a result of over-pricing in the commercial rooftop PV, but overall, the value is lower than in Europe and the USA. Generally, there is a global downward trend.

Figure 2.12 makes a comparison of PV LCOE in South Africa with grid electricity from Eskom based on the Multi-Year Price Determination (MYPD), which is a regulatory methodology used to determine Eskom's price increases. The graph shows different Eskom tariff increase scenarios and expected grid parity. The lower range scenario represents large installations, and the upper range arises from the fact that as the installations become smaller, the LCOE increases. The expected year of reaching grid parity was 2018 (for the lower range). At this stage, it became economical for customers to generate own PV electricity rather than relying on grid supplies generated by Eskom. Municipal customers, however, pay the municipal electricity utility rates, which are higher than Eskom rates (mainly because municipal electricity utilities purchase their electricity from Eskom and resell with an added margin). The result of this is a higher LCOE of the municipal grid. Therefore, PV LCOE would have reached grid parity earlier compared to Eskom grid LCOE.

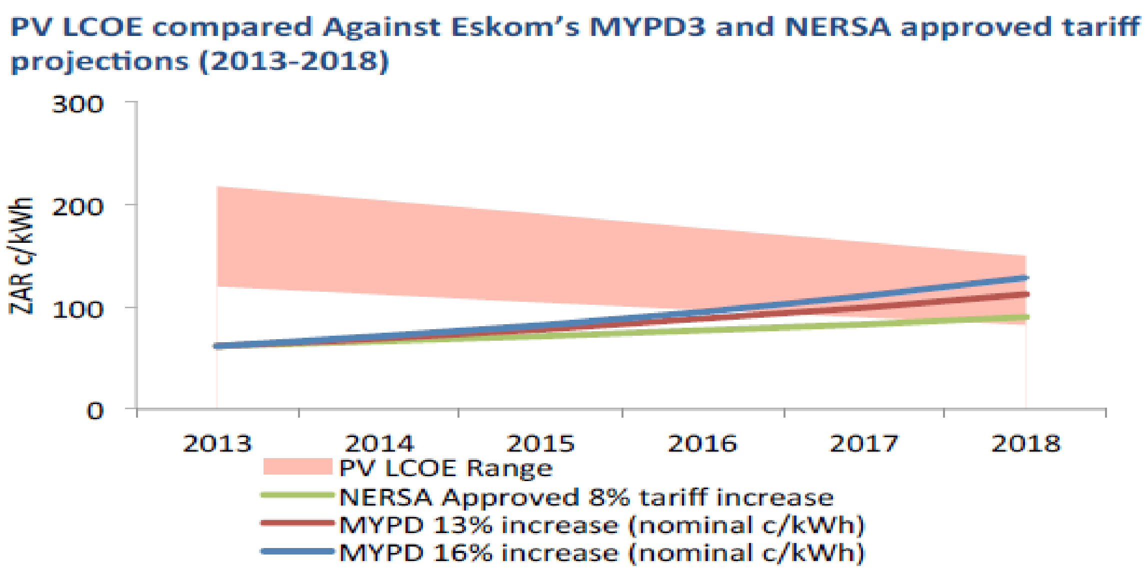

Figure 2.12: A comparison of PV LCOE with Eskom electricity under different price increase scenarios (source: SAPVIA, 2013, page 30).

2.4.4 Smart-grid technology and energy storage-digitalisation

The conventional electrical distribution system involves the transmission of electricity generated from a central power plant by transforming it to a higher voltage level and subsequently reducing it to a lower voltage level for delivery to end-use customers. In the modern context, this model fails to recognise the value of information within the system, as well as the significance of the emerging energy storage technologies. The model also lacks the capability for remote monitoring and control. The introduction of distributed PV generation ensures that energy is generated closer to the consumption site and results in minimisation of losses (both technical and non-technical). Distributed PV generation also implies that the need for monitoring increases due to the need to read and manage data for improved load management in order to mitigate uncertainty over available capacity at any instant in time. This highlights the increasing relevance of the adoption of a smart grid, which entails capabilities such as remote meter reading, data communication technologies, demand response, network monitoring and network automation. These capabilities can be implemented in line with the priorities of the utility. Smart grids present benefits such as reduction of power outages caused by overload, real-time communication, improved response time and ability to manage supply and demand (Bayindir et al., 2016).

The implementation of the smart grid system would also ensure that the utility could access metering information and be able to monitor other parameters, such as the quality of the power generated by the respective distributed PV systems. This capability greatly improves the quality of supply while reducing the workforce required to achieve this. The shift from centralised to decentralised energy systems requires real-time monitoring and control of the grid through a bi-directional flow of information. This requirement would be best addressed through the smart-grid system, which is characterised by the utilisation of technology to transfer data from customers or the grid back to the operator for decision making on a real-time basis in order to improve on efficiency. The smart-grid thus enhances capabilities for measurements and control across generation, transmission, distribution as well as system-dynamics/behaviour on the customer side. The deployment of energy storage – in a supplementary role – becomes relevant to the smart-grid (Zame et al., 2018, page 1651).

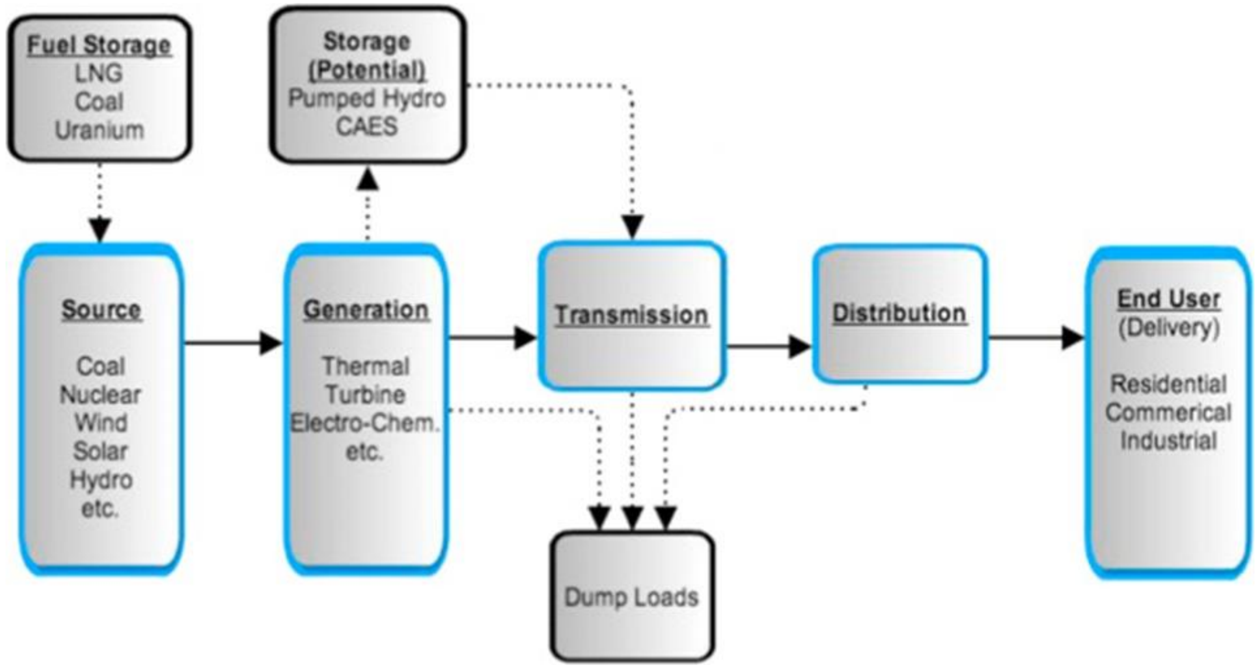

Figure 2.13: The conventional grid value chain (source: Zame et al., 2018, page 1648).

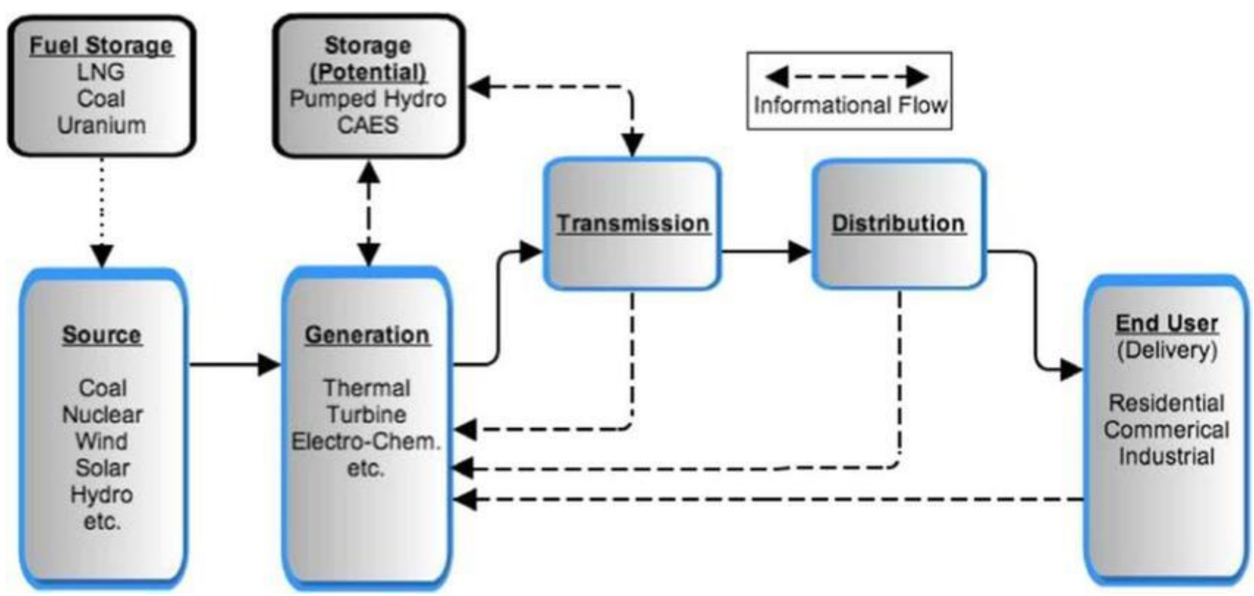

Figure 2.14: The smart-grid value chain (Source: Zame et al., 2018, page 1648).

Zame et al. (2018) refer to a smart-grid network as a visualised communication network of the future, which is also suitable for distributed PV integration/monitoring and management. The smart-grid main components include smart meters, two-way communication networks, automation/smart sensors, and control and management centre. The communication network component of the smart grid is either analogue, digital or both. The smart grid therefore serves the dual role of a communication infrastructure that connects the renewable energy source, such as distributed PV to the grid. However, the connection of distributed PV generation to the grid comes with challenges, such as power stability and quality, and complicated operating processes (Hossain et al., 2016). The success of smart grids is dependent on the robustness and security of the information transmission infrastructure. Energy storage is another asset class, which has the potential to change the entire electricity value chain but currently has feasibility limitations (Zame et al., 2018).

2.5 Data management and transacting

2.5.1 Current data management practices of municipal utilities

Municipal utilities in South Africa currently utilise centralised database systems to manage the metering data from customers' meter installations. In the post-paid meter set-up, the utilities conduct a manual reading of data which requires a site visit each time whereas in prepaid billing system the meter owner purchases a token from the utility (cashier) or third-party vendor. This is where the information on the meter purchases is recorded and stored in the database server. In the case of distributed PV, the utility can read the meter remotely using online metering technology. However, the data would still be stored in the centralised database server. Figure 2.14 shows the current meter and data management process for CoE, which is vulnerable to tampering. The key vulnerability points in the system include lack of bi-directional communications between meter and utility and a single database without back-up system.

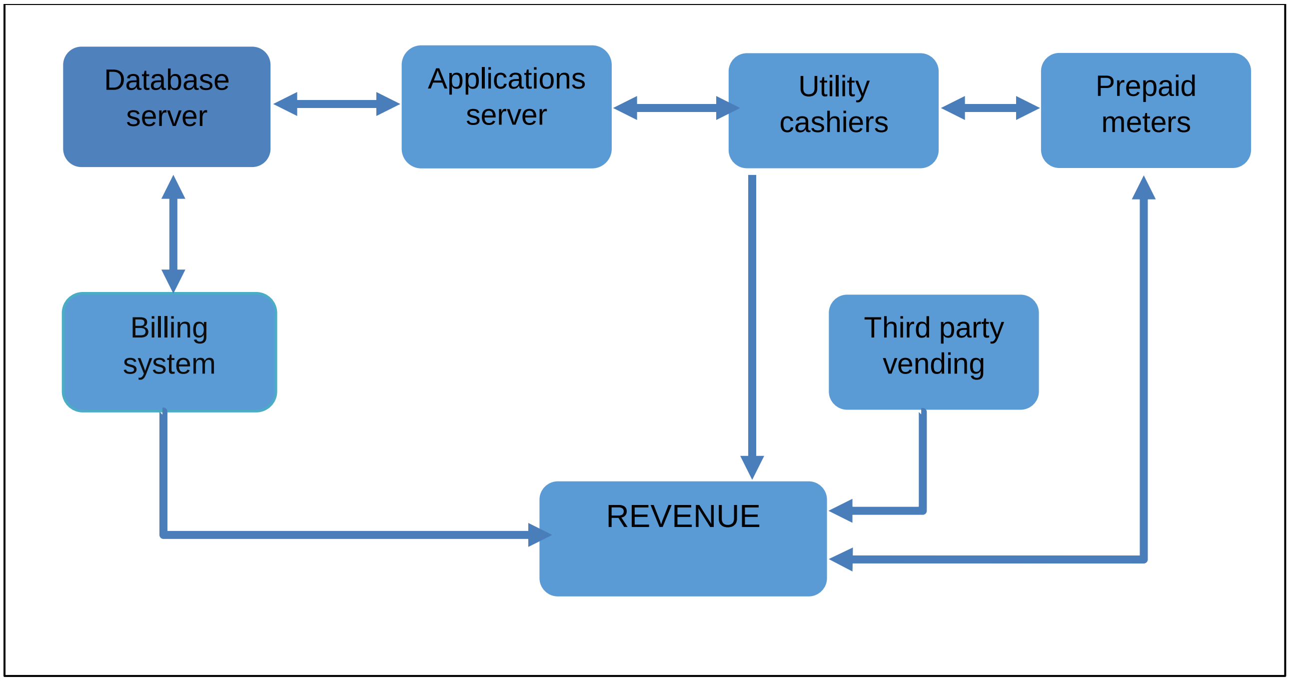

Figure 2.15: Process diagram for data management for the electricity retail model for CoE (Source: conceptualised from secondary data and own experience at CoE utility).

2.5.2 Blockchain

In the last few years, the energy sector has started to engage with the emergence of blockchain technology (BCT) as a significant digital innovation that is rapidly becoming relevant. BCT is used in many applications under smart grids in the conveyance of secure information, such as energy transactions (ACEEE 2018). Masters (2018) notes that blockchain is a technology platform that promises error-free transactions while improving efficiency, reducing administrative costs, eliminating fraud and facilitating regulatory reporting requirements. Metering, data collection and cybersecurity will increasingly become critical components of the revenue collection system as the distributed PV generation market progresses globally.

Kumar (2018) defines BCT as a distributed ledger-based technology which is increasingly being utilized for digital transactions. It particularly addresses security concerns when performing transactions through the internet of things (IoT). The technology collects information from the various information sensors that can be attached to multiple items and creates a distributed ledger-based database. The technology has more intelligence than IoT, and this facilitates a shift from centralised database to decentralised database, as shown in Figure 2.15.

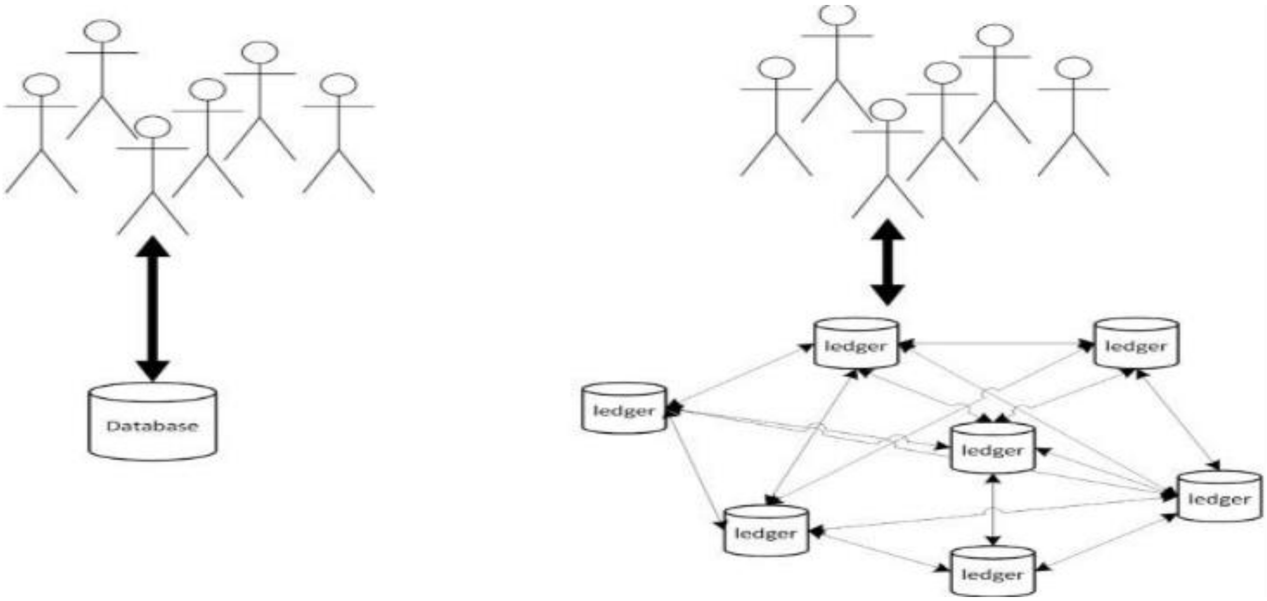

Figure 2.16: The shift from a centralised to blockchain approach in data and operations management (Kumar, 2018 page 4).

2.5.3 Exploring the role of Blockchain role in distributed PV generation

The emergence of distributed PV generation requires the collection of data from a diverse range of DES locations/technologies and the management of the data flow. BCT provides the capability to collect information on real-time performance of the systems, predict yield and financial flows and store the information on distributed ledger-based format. The ledger-based blockchain technology removes the security risk of hacking by providing a highly secured data flow environment. With BCT, it is possible to manage (under real-time conditions) the multiple DES connections feeding to the same grid. BCT allows these data to flow without interference, especially based on the ledger-based distributed networks, which allow for the duplication of each energy data transaction with time label as per the accessing protocol (Kumar, 2018:5).

2.6 Consolidation of insights and conceptual framework of the study

The literature review provides insights and the theoretical framework that builds towards answering the main research question on the conceptualisation of the responsive, innovative business model. Analysis of the mapped current municipal business model in Figure 2.2 shows one of the weaknesses of a tariff structure that is rigidly coupled to revenue from electricity sales. This creates a problem when electricity sales decline (as is expected when distributed PV generation increases on the customer's side). The declining PV LCOE and the declining PV equipment costs are creating an environment where consumers are opting for distributed PV self-generation to reduce their electricity costs. This trend leads to the erosion of municipal revenues, and as a result, municipal power utilities need to innovate new business models to mitigate this impact. The reviewed literature further identifies important efficiency parameters that have an impact on municipal revenue. These parameters are the CoS, tariff design, and operational efficiency, which includes EEDSM, electricity losses and LCOE. These parameters are very important in a municipal business model (either existing or new).

In addition, literature review shows various approaches to alternative business models that have been implemented in countries such as Germany and also provide insights on conceptualising a responsive business model for municipal power utilities in South Africa. The critical factors emerging from the literature review include an assessment of the power utility's cost of supply, operational efficiencies and innovative smart-grid and similar digital technologies towards more efficient operations and maintenance. The literature review also introduces the Business Model Canvass (BMC) and its application in the mapping of existing business models, as well as in developing new business models. This tool that will ultimately be utilised in this study to guide the conceptualisation of the proposed business model as well as assessing its applicability in this study.

3 RESEARCH METHODOLOGY

3.1 Introduction

This chapter presents the research approach as well as methods and tools for data collection and analyses. The study involved an analysis of primary and secondary data for CoE as the case study to determine the baseline (business-as-usual) revenue performance under a distributed generation scenario with PV technology. The chapter also reviews the current business model based on CoE purchasing electricity from Eskom and distributing it to the customers under its jurisdiction. Insights from the analysis was then used to conceptualise a responsive business model aimed at safeguarding the municipality's revenue under increasing investments in distributed PV within the licensed area of the municipal utility. The final section of the chapter presents the ethical considerations of the study and how they were addressed.

3.2 Research Design Approach

The study applied a qualitative approach primarily based on qualitative data tools and the derivation of findings. In some instances, numerical data were analysed and used to answer some of the sub-questions, but the approach was mainly qualitative. Bui (2014) notes that non-numerical studies can take different approaches (e.g. case study, phenomenology, grounded theory, ethnography or participatory action research). Quantitative research differs from qualitative research in that the former approach relies primarily on a statistical analysis of numerical data in order to respond to the research question

Having prioritised a qualitative approach, the study then applied a purposely selected case study method where primary and secondary data from CoE were collected and analysed to guide the conceptualisation of a responsive business model applicable to the respective municipal utility. The case study method thus allowed for the appraisal of an empirical context of the disruptive force of distributed PV generation on conventional electricity value chain and the impact on municipal revenues. A case study research thus allowed for an inquiry on distributed generation as a contemporary phenomenon within its real-life context especially focusing on a utility where the boundaries between the phenomenon and its context are not evident and thus multiple sources of data evidence were needed (Yin, 1994).

Having prioritised the case study method, the different stages of the study and the conceptual framework pursued towards the responsive model are summarised in Figure 3.1.

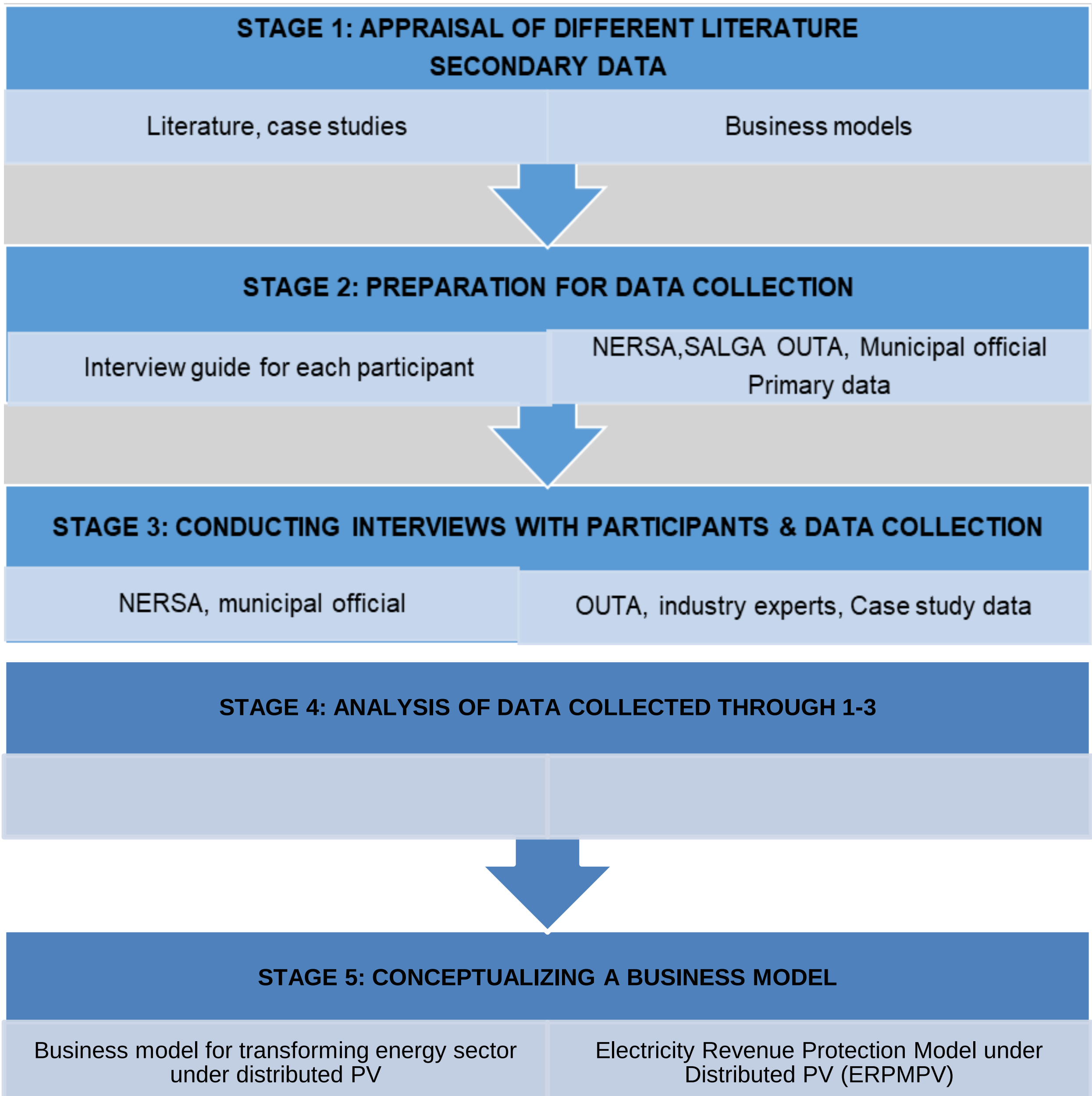

Figure 3.1: Key stages of the study process towards the responsive business model.

The first stage of the study involved building the research questions, identification and motivation of the case study, and undertaking literature review of the different theoretical themes underpinning the study. Some of the studies reviewed also served as secondary data sources primarily for answering Sub-question 1 as presented in Chapter 4.

The second stage involved the preparation of data collection tools. These were the interview guides used for collecting primary data during interviews with selected industry participants. In order to adequately address each sub-question, each participant was presented with questions relevant to their participant category (civic groups representatives, industry experts, regulatory representatives, municipal representatives and financiers).

The third stage involved data collection through interviews with the purposely selected participants. Each participant was presented with questions relevant to their environment and line of expertise (as guided by the participant groups identified in stage two). The municipal official was presented with questions relating to the first sub-question on municipal revenue performance data for the past 10-years (covering the period 2009 to 2018). The NERSA official was presented with questions relating to the regulatory environment in South Africa. Industry experts were also interviewed and presented with questions that probed their views on a relevant business model to safeguard revenue for municipalities in South Africa. The views of civic organisations were also sourced in order to get the views of the broader society. SALGA (as an association of local governments in South Africa) was presented with questions relating to local governments perspectives as well as soliciting their views on responsive regulatory frameworks to support the current envisaged innovations on business models of the municipal utilities owned and operated by municipal authorities as its members.

The fourth stage involved analysis of the collected data in determining the municipal revenue performance trend for the 10 years from 2009 to 2018 as well as identifying the different parameters that contributed to the fluctuation of the electricity revenue of COE as the case-study municipality. The literature review provided the researcher with insights into the possible mechanisms that could be considered or evaluated in addressing the revenue loss arising from the increasing adoption of distributed PV. The mitigation mechanisms identified included decoupling in rate designs. Various case studies demonstrated the effects of the different components of rate design. This stage also consolidated the views of the selected industry stakeholders who participated in the interview process. These views ranged from regulatory, financing and societal concerns on the disruptions facing the key actors/stakeholders in the electricity value chain and market.

The fifth and last stage involved consolidating the analyses and sub-findings to inform the conceptualisation of the responsive business model. In conceptualising the appropriate model, the revenue impact of the current transition was analysed, considering both the current municipal revenue performances and the future expected trajectory given the scenario of increased adoption of distributed generation. It was important to factor in the recovery of revenue from all areas of current wastage, which thus raises the relevance of energy efficiency and demand-side management. The final recommendations identified both micro and macro constraints that can affect the viability of the model and possible responsive interventions. This includes the need for greater stakeholder cooperation to overcome potential challenges and a seamless transition to new electricity value chains, which effectively allow for a more systematic adoption and integration of distributed PV generation.

Based on the insights from literature review, the conceptual framework was formulated as follows: Incentivised by declining LCOE of distributed generation (DG) based on rooftop PV technologies, the increasing adoption of DG by customers of municipal utilities as electricity distributors in South Africa poses the risk of revenue erosion for the utilities. This poses additional risk of unviability and undermining service delivery for other municipal services which are often cross-subsidised from the margins on the retail of electricity primarily procured from Eskom. This underlying risk and vulnerability constitute the motivation for appraising alternative business model for the utilities which would not only mitigate the risk but also incentivise adoption of DG by customers. In developing the conceptual framework, the identified variables from the insights are LCOE, tariff structure, customer's electricity consumption and utility efficiencies which are all linked to the municipal utility's revenue.

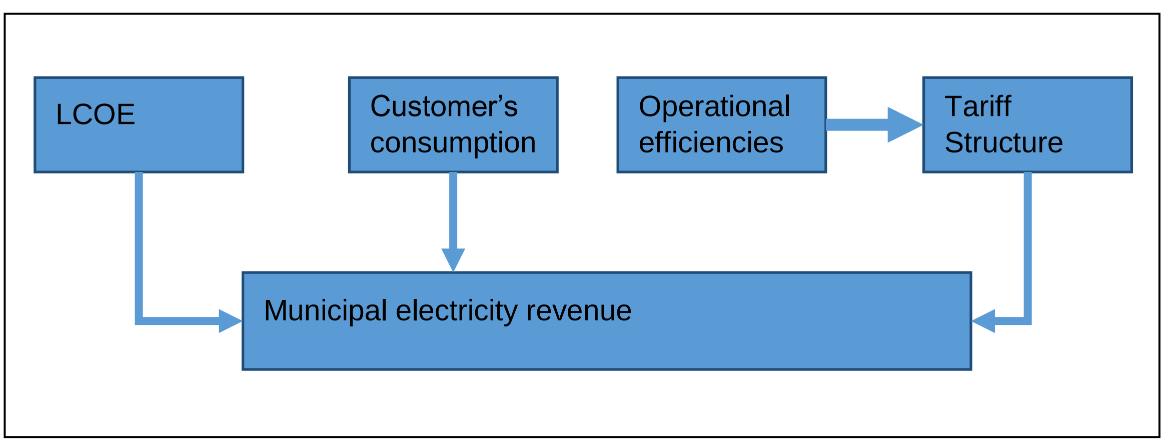

Figure 3.2: Conceptual framework for the development of the responsive business model

3.3 Sampling Techniques

Arising from the qualitative approach of the study, purposeful sampling was prioritised for both the case study of CoE as well as the interview participants for primary data collection. CoE was prioritised as a case study due to ease of access to data and interview participants. Given that current electricity business models and local governance and regulatory frameworks for municipal utilities are relatively similar for South Africa, there is an extent to which CoE can qualify as a representative case of municipal utilities in the country. However, such representativity is not a critical criterion of the study given that it does not aim at generalisation of the findings across the diverse municipal landscape of South Africa.

The collection of primary data was achieved through semi-structured interviews while secondary data were collected from media articles, government reports, policy documents and academic journals. The interview process involved open-ended, semi-structured interviews where participants were asked questions relating to the problem under investigation. The aim was to solicit their views as experts along their respective knowledge-fields and roles in the sector. Semi-structured interview was prioritised as it allows the researcher to initially prepare guiding questions while allowing for follow–up questions guided by the interviewee's initial responses (Chu and Ke, 2017). This contrasts with structured interviews which allow for presentation of the same questions in the same order.

Most of the secondary data were collected from the Energy Department of CoE and were used to establish the baseline trajectory over the last 10-year period (from 2009 to 2018). These data covered municipal sales over the research period and extended data relating to notified maximum demand as well as related electricity rates paid to Eskom for the bulk supply. Additional secondary data was extracted from academic journal articles as well as government policy documents and reports.

For the data analyses stage, Excel software was used to analyse numerical data as well as for developing trends based on graphs. The data were coded in different colours to highlight which data represented the actual sales and which data represented the years in which those sales were made. The complementary secondary data related to both technical and non-technical losses. Open-source online software by the National Renewable Energy Laboratory (NREL) was applied as the basis for COE climatic database, with radiation levels as the key data of interest for the study. The data were used to derive the potential energy generation of a PV plant in order to estimate the potential impact on current municipal revenues. Table 3.1 provides a summary of the data collection methods, the nature of the data collected, and the respective sub-question the collected data were meant to address. The final part also provides information on the chapters where the findings related to the sub-question are presented and analysed.

Research sub-question	Data collection and tools	Data analysis process
1. What is the business-as-usual revenue performance of the City of Ekurhuleni?	**Secondary data**: CoE Sales and revenue data for a 10-year period were provided by the official and retrieved from the *eVenus* financial system.	These data were analysed and processed using an Excel spreadsheet to develop a trend using the chart function. A narrative was developed using additional data provided, such as the losses and consumption incurred in the 10-year period. This analysis is covered in Chapter 4 of this report.
2. What is the magnitude of the revenue erosion, given the scenario of distributed PV generation?	**Secondary data**: Reported data on PV DG LCOE for South Africa was sourced from literature, these data have been published by the Council for Scientific and Industrial Research (CSIR) CoE Customer data in different customer categories provided by the municipal official and verified by the researcher on the customer database. **Primary data:** Data on registered installations were collected by the researcher over a period of time. The installation-owners/developers are required by law to complete an application form and the existence of the system as to be verified.	Chapter 5 of the report covers this sub-question. The customer data were used to calculate the maximum possible erosion on revenue that the CoE could expect over time. Data on distributed PV systems were analysed using Excel to generate the growth trend; a further extrapolation was made to check the growth that can be envisaged over a 10-year period.
3. How can the revenue gap be addressed?	**Secondary Data:** Literature on innovative business models for managing PV DG.	Data obtained from secondary sources provided an insight into the available options of addressing the revenue gap that distributed PV is expected to create. Parameters were identified that are crucial to revenue enhancement, such as energy efficiency and demand-side management. This research sub-question is addressed in chapter 5 of the report.

4. What is the responsive business model	Secondary Data: insights from various innovative business models locally and internationally on DG.	Chapter 6 of the report is a consolidation of sub-findings used in sub-question 1 to 3. Appraisal of innovative business models globally for effectiveness and insight. Improve and formulate an innovative and responsive model.
5. Overall findings, recommendations and conclusions		

Table 3.1: Data collection and analysis table in relation to sub-questions.

3.4 Data Overview

Sub-question question 1: *What is the business-as-usual baseline revenue performance of the City of Ekurhuleni?*

To respond to this question, interviews were conducted with municipal officials from the energy and the finance departments of CoE. The finance department collects primary data relating to revenue collection and manages all meter readings and billing, whereas the energy department is responsible for the rate design, meter installations and management, as well as electricity customer profile on the municipality database. The energy department manages the entire electricity operations.

Secondary data sources used include the municipal tariff policy and tariff booklet. These data sources assisted in determining the current rate design and collection process. Additional secondary data were collected from the municipality's GDS2030 strategic documents. Identifying the relevant participants from the municipality was a simple task as the researcher is also an employee of the municipality. The participant who was identified was also targeted as an industry expert based on his participation in industry forums such as the Association of Municipal Electricity Undertaking (AMEU), which is a body that represents all municipal electricity distributors. The participant was cooperative in responding to the interview questions and participated meaningfully. Further information in the form of documents was provided to support the oral submissions made during the interview. The municipal management office supported the study and provided permission to conduct the interviews. A summary of the interview transcript is attached as Appendix M.

Sub-question 2: *What is the magnitude of the revenue erosion, given the scenario of distributed PV generation?*

Secondary data on PV LCOE were collected, analysed and utilised to generate the distributed PV scenarios. In addition, interviews with municipal officials were conducted to solicit their views on the current LCOE trajectory and its impact on municipal revenue.

Sub-question 3: *How can the revenue gap be addressed?*

Secondary data on the various approaches to mitigating the impact of revenue erosion were collected from published articles. Interviews were also conducted with municipal officials, civil society groups (such as OUTA) and industry experts.

Sub-question 4: *What could be a responsive business model?*

Secondary data were sourced from the energy department on the current municipal business model and analysed to identify weaknesses in relation to the ongoing transition. The necessary changes were proposed based on further analysis of secondary data from journal articles and primary data from interviews with industry stakeholders such as NERSA, industry experts, SALGA officials, financiers and civil society groups.

Industry experts were interviewed at the South Africa Energy Storage, SSEG and Smart-grid 2018 conference held at the Emperors Palace, on 22 and 23 October 2018. However, one municipal official was also identified as an industry expert and was interviewed under this category. A summary of the interview transcript is attached as Appendix M.

Given that the researcher previously worked for NERSA, this assisted in identifying the relevant participant with expertise in tariff design and pricing. The participant was formally requested to participate in the interview sessions. A summary of the interview transcript is attached as Appendix P.

Interviews were conducted with two participants from the civil society organization named Organization Undoing Tax Abuse (OUTA). OUTA's main purpose is to protect the consumers from "unfair" treatment by Government and other statutory bodies especially in the course of implementation of Government policy or legislation. OUTA supports the SSEG registration process and believes that the regulatory environment should be relaxed to accommodate alternative and renewable energy generation by the private sector and consumers. They are aware of the negative impact this might have on municipal revenue and also suggested that municipalities relook at their business models in order to survive this transition. Consumers who can afford it should proceed and generate their own electricity and be able to sell to the grid at agreed rates. A summary of the interview transcript is attached as Appendix N.

The DBSA official was identified and interviewed at the Development Bank of South Africa (DBSA) offices in Midrand. Data and insights into the current financing models for municipal infrastructure development, especially in renewable energy sector, were provided. The interviewee gave a short introduction of DBSA and its role in funding development infrastructure in South Africa and the entire African continent. The DBSA manages the climate change fund among other financing options that are accessible to municipalities and private companies for the development of relevant eco-friendly projects. A summary of the interview transcript is attached as Appendix Q.

The SALGA official responsible for municipal operations was interviewed at their office building. The interview focused on research conducted by SALGA which relates to this study. They provided permission and relevant documents relating to the distributed PV work already conducted. The interview questions sought to understand the relevance of current business models, regulatory framework and the impact of PV distributed generation on municipal revenues. A summary of the interview transcript is attached as Appendix L.

3.5 Ethical Considerations

The research ethics requirements of the University of Witwatersrand provided guidance for this study. The relevant documents required by the University of Witwatersrand in relation to compliance with the ethical standards were completed (copy of the clearance certificate is attached to this report as Appendix K). As part of the ethics clearance requirement, a permission letter was obtained from the Energy Department of the CoE for allowing access and utilisation of their non-confidential and also publicly available data. Being an employee of the CoE, the researcher remained aware of the risk of potential conflict of interest or bias in data analysis and presentation of findings. For example, the study is based on the assumption of preferred continued operations of municipal power utilities as given. It is likely that another researcher without such linking to the industry could question the assumption as the issue for research. Given that this study was undertaken solely for academic purpose, modalities of related implementation of findings by the CoE or other municipalities were delimited as beyond the scope of the study.

4 CITY OF EKURHULENI BUSINESS-AS-USUAL REVENUE PERFORMANCE FOR COE

4.1 Introduction

This chapter presents an analysis of data related to the sub-question on the business-as-usual revenue performance of CoE. It starts by presenting an overview of the case study area and some background information focusing on aspects that influence electricity revenue performance for CoE, such as the electrical network types, customer categories, points of delivery and the demand of the points of delivery. The subsequent sections present the baseline case findings on the electricity revenue performance, followed by a presentation of the results from the data analyses.

4.2 Brief Overview of the Case Study - CoE

CoE is a category A South African municipality with exclusive executive and legislative authority within its area of jurisdiction as described in the Municipal Systems Structures Act. It covers an area of about 1,975 km², which constitutes 12% of the area of the Gauteng Province. The City is located in the former East Rand area (see Figure 4.1). The municipality came into being in 2000 after the amalgamation of nine different towns and 17 different townships, as well as portions of the Kyalami Metro and the Eastern Gauteng Services Council (CoE, 2016). Following the amalgamation, CoE became one of the country's largest Metros as well as one of the largest distributors of electricity, with a population reported at 3.17 million as per 2011 census (Statistics South Africa 2011). The City has 1,084,363 households, of which 782,011 have access to conventional electricity, while 63,633 have access to alternative sources of lighting (including solar home systems). The remaining 238,719 have no access to electricity at all and this includes households in the 119 informal settlements within the city (CoE, 2016).

CoE is highly urbanised, with 99.4% of its population residing in urban settlements ranging from informal settlements to high-income residential suburbs. There are several large urbanised townships, such as Katlehong and Tokoza, that are historically apartheid townships initially developed specifically for the black population. Informal settlements are mainly temporary dwellings for migrant workers coming from different parts of South Africa and beyond in search of better living conditions.

The operating income of CoE for the 2015/16 financial year was R32 billion with service charges as the main source of revenue. In the 2015/2016 financial year, CoE collected R17 billion on diverse service charges. In the same period, it experienced a 2.73% decrease in electricity revenue in line with a decline in electricity sales (CoE, 2016). The decline could possibly be attributed to energy efficiency and demand side management aimed at reducing consumption and demand within CoE's licensed area of supply and nationally. Data collected through interviews shows that only 0.26% of the 2.73% decrease in revenue could possibly be attributed to blackouts.

Figure 4.1: CoE and its main townships (Source: CoE, 2016).

4.3 The Electricity Supply Network Configuration

CoE is the main distributor of electricity within its boundaries (licensed area), but a few of its residents are in areas that are supplied directly by Eskom distribution. The municipal power utility purchases its electricity from Eskom distribution and resells to its customers at a margin. CoE also purchases a very small portion (0.04%) of its electricity from the neighbouring municipal power utility, City Power, due to the latter's infrastructure being closer to a few of CoE's customers and readily available for use. The electricity is delivered by Eskom at transmission-voltage levels through eight Eskom owned substations:

- NEVIS 275/132kV with 2 × 500MVA and 132/44kV with 2x90MVA
- PIETERBOTH 275/88kV with 2 × 315MVA
- BENBURG 275/132kV with 2 × 250MVA
- EIGER 275/88kV with 3 × 315MVA
- JUPITOR 275/88kV with 3 × 180MVA
- BRENNER 275/88kV with 3 × 315MVA
- CROYDON 275/132kV with 2 × 250MVA and 132/44kV with 3 × 80MVA
- ESSELEN 275/132kV with 1 × 250MVA and 2 × 180MVA and 132/88kV with 2 × 160 MVA

The geographical locations of the eight Eskom transmission substations supplying CoE are shown in Figure 4.2:

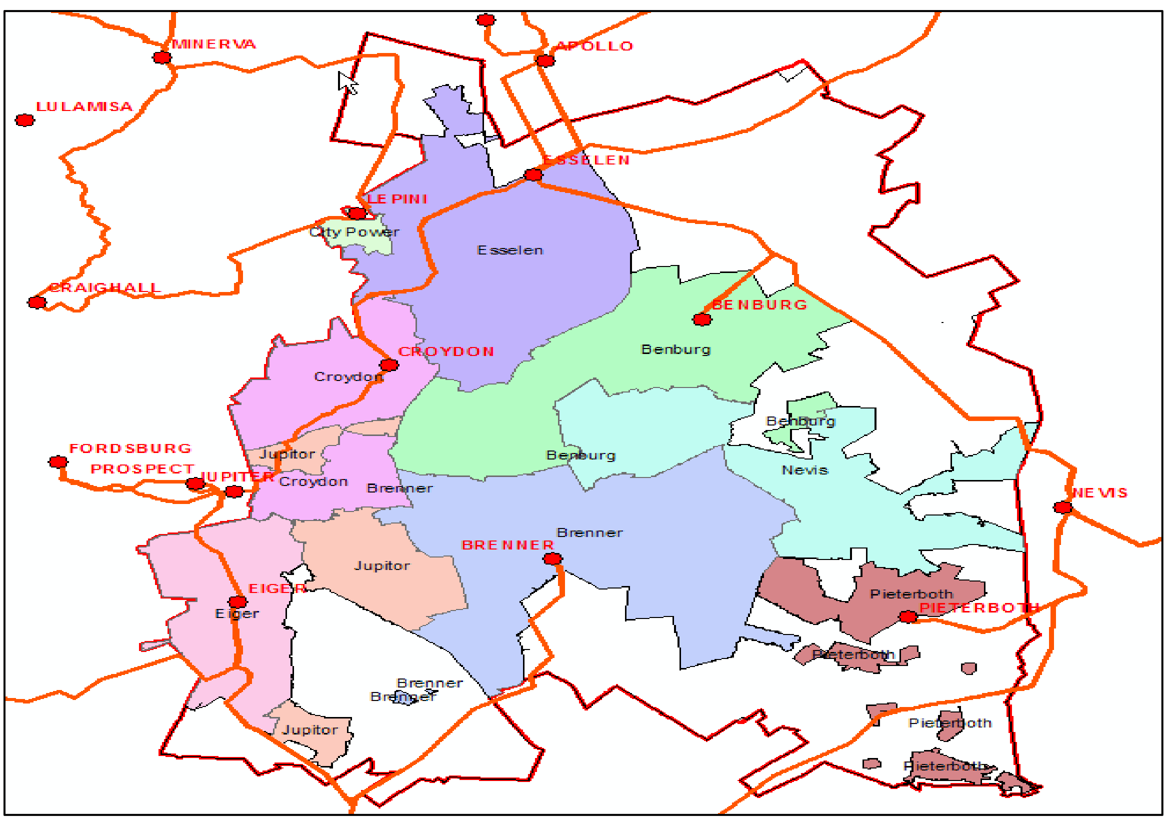

Figure 4.2: Geographical locations of the eight Eskom owned transmission substations feeding CoE (Adopted from data collected from interview with municipal official participant).

The substations supply CoE through 56 municipal-owned Points of Delivery (PoDs). A combined total demand of between 2000 MVA to 2500 MVA is supplied to CoE at these 56 PODs daily. The fluctuations in demand are caused by various factors such as weather and consumption patterns by the consumers. Power is transmitted from the eight Eskom transmission substation to CoE 's 56 PoDs through multiple Eskom owned networks of 132/88/66/44/33/11/6kV. The CoE currently has 24 contracts with Eskom for the supply of power stemming from the previous dispensation before the amalgamation of the different cities to form CoE. These contracts are yet to be revised to incorporate the changes that occurred in 2000 when CoE was formed. Based on the historical contracts, each POD receives power from Eskom at Eskom tariffs, as approved by NERSA.

4.4 Presentation of business-as-usual baseline revenue performance data

This section presents data related to the business-as-usual municipal revenue performance for the research period spanning between 2009 and 2018. The relevant secondary data were sourced from a municipal official, who was also one of the interviewees for this study. The data collected from the municipality included invoices issued as evidence of electricity purchases from Eskom. This information was captured by municipal officials into their financial system called *eVenus*.

4.4.1 Notified maximum demand and energy purchases by CoE

Municipal electricity utilities/distributors purchase their electricity mainly from Eskom SOC and resell to their customers at a margin above the cost. This electricity is delivered by Eskom to the municipality through 56 different points of delivery (PoDs). Secondary data relating to the demand measured at CoE's PoDs were collected and presented as shown in Appendix A. Furthermore, purchases data for the 10 years from 2009 to 2018 were retrieved from the *eVenus* system. The data comprised of the energy purchases and the corresponding average Eskom price per unit of electricity for that year to give the total monetary value of purchases. Based on the data, the total Notified Maximum Demand (NMD) for the CoE is 2,525 MW. The NMD is notified demand to Eskom in writing, and it is not to be exceeded. Should the NMD be exceeded, Eskom is then within its right to implement penalties.

Table 4.1 shows that the average annual electricity purchases from Eskom over the period of interest for the study were 10,722,439,168 kWh. The purchases peaked at 10,974,168,017 kWh in 2008/9, and the minimum amount was 10,483,275,363 kWh in 2015/6. The annual purchases were relatively stable with minimum variation, thus implying consistency in supply and demand. However, the annual total purchases declined by an average of 0.37% per annum. This decline in purchases was explained by constrained supplies from Eskom and increased use of alternative energy sources. If the environment had remained stable, purchases should have grown in line with economic and population growth statistics for CoE. For example, the population of CoE increased from 2.8 million in 2011 to 3.6 million in 2016 and the unemployment rate also increased from 23.6% to 26.3% over the same period (CoE, 2018). The increase in unemployment has a direct impact on spending. Despite a huge increase in the population, unemployment rate only rose from 23.6% to 26.3% as the population growth was largely driven by economically active people from other regions who managed to secure employment opportunities within CoE. Most of the migrants were being absorbed into employment resulting in unemployment increasing at a lower rate than population. Population growth did not significantly impact on electricity consumption possibly because a significant portion of the new residents were low-income earners who ended up settling in informal settlements without access to electricity, while some moved to low-income residential areas.

Year	**kWh**	**% Change**
2008/09	10,974,168,017.00	
2009/10	10,796,407,663.00	-1.62%
2010/11	10,843,712,630.00	0.44%
2011/12	10,887,124,231.00	0.81%
2012/13	10,810,969,437.00	-0.70%
2013/14	10,725,291,900.00	-0.79%
2014/15	10,547,885,924.00	-1.65%

2015/16	10,483,275,363.00	-0.61%
2016/17	10,543,768,792.00	0.58%
2017/18	10,611,787,723.00	0.65%
Annual average purchases	**10,722,439,168**	**-0.37%**

Table 4.1: Total business-as-usual electricity purchases of CoE in kWh over 10 years (2008–18).

4.4.2 Energy sales by CoE

The municipal electricity distribution value chain (see discussion in Section 2.2) shows that the municipality is both a distributor and retailer of electricity to its customers. The data presented and analysed in this section are secondary data collected from CoE's *eVenus* system which contains data for over 10 years as summarised in Table 4.2. Electricity sales increased marginally on average by 0.97% annually over the review period, indicating that the rate of electricity uptake did not significantly increase.

Year	Annual sales (kWh)	Annual Change (%)
2008/09	9,769,204,368.73	-
2009/10	9,183,424,358.15	6.0%
2010/11	9,308,242,921.59	1.4%
2011/12	9,183,424,358.15	-1.3%
2012/13	9,719,061,523.86	5.8%
2013/14	9,183,424,358.15	-5.5%
2014/15	9,474,494,696.42	3.2%
2015/16	9,183,424,358.15	-3.1%
2016/17	9,309,093,466.46	1.4%
2017/18	9,379,317,010.54	0.8%

Annual Average	**9,369,311,142.02**	**0.97%**

Table 4.2: Electricity sales (kWh) for CoE for financial years 2008/09–2017/18) (Source: eVenus system).

Table 4.3 shows performance in terms of the different losses categorised by financial years from 2008/9 to 2016/17. On average, annual technical losses were estimated to be 5.90% for the City. The data shows that non-technical losses began to increase from 2013/14, and the situation has been worsening ever since. Total losses are calculated by subtracting the final sales from purchases.

Year	Total Losses	Non-Technical	Technical losses
2008/09	10.98%	5.08%	5.90%
2009/10	14.94%	9.04%	5.90%
2010/11	14.16%	8.26%	5.90%
2011/12	11.00%	5.10%	5.90%
2012/13	10.10%	4.20%	5.90%
2013/14	10.01%	4.11%	5.90%
2014/15	10.18%	4.28%	5.90%
2015/16	11.35%	5.45%	5.90%
2016/17	11.71%	5.81%	5.90%

Table 4.3: Technical and non-technical losses per financial year (Source: eVenus system).

Table 4.4 shows a comparison of both non-technical and technical electricity losses suffered in 2018 by the Gauteng metros with a combined annual loss of R5.1 billion. However, CoE performs better than the other two metros. Non-technical losses contributed the most for CoE and these were mainly as a result of theft, vandalism and meter by-passes (Table 4.3).

	City of Johannesburg	City of Tshwane	City of Ekurhuleni	Category total(R)
Electricity losses: Technical (R)	970,589,000 (9,36%)	525,214,233 (6.99%)	543,313,133 (5.9%)	**2,039,116,366**
Electricity losses: Non-technical (R)	1,537,624,000 (14.82%)	999,407,654 (13.32%)	533,183,567 (5.79%)	**3,070,415,221**
City total (R)	**2,508,213,000**	**1,524,621,887**	**1,076,496,700**	**5,109,531,587**

Table 4.4: Electricity losses for Gauteng's metros in 2018 (De Wit, P, 4 February 2019 www.businessinsider.co.za).

Table 4.4 also shows technical and non-technical losses expressed as a percentage of bulk electricity purchases. The City of Johannesburg is the most affected, contributing almost 50% of the losses at R2.5 billion. In 2018, Johannesburg and Tshwane lost over 20% of the gross electricity purchases.

4.5 Data Presentation, Analysis and Sub-findings

4.5.1 NMD and purchases and sales

This section presents an analysis of the data on the baseline (business-as-usual) revenue performance of CoE. Figure 4.3 presents the NMD for the various PoDs of CoE. The power demand in kVA for the different municipal areas of CoE covers the following towns: Brakpan, Tembisa, Benoni, Edenvale, Springs/Nigel, Alberton, Kempton Park, Boksburg and Germiston. The total carrying capacity of the 56 PoDs is calculated to be 2,525 MW.

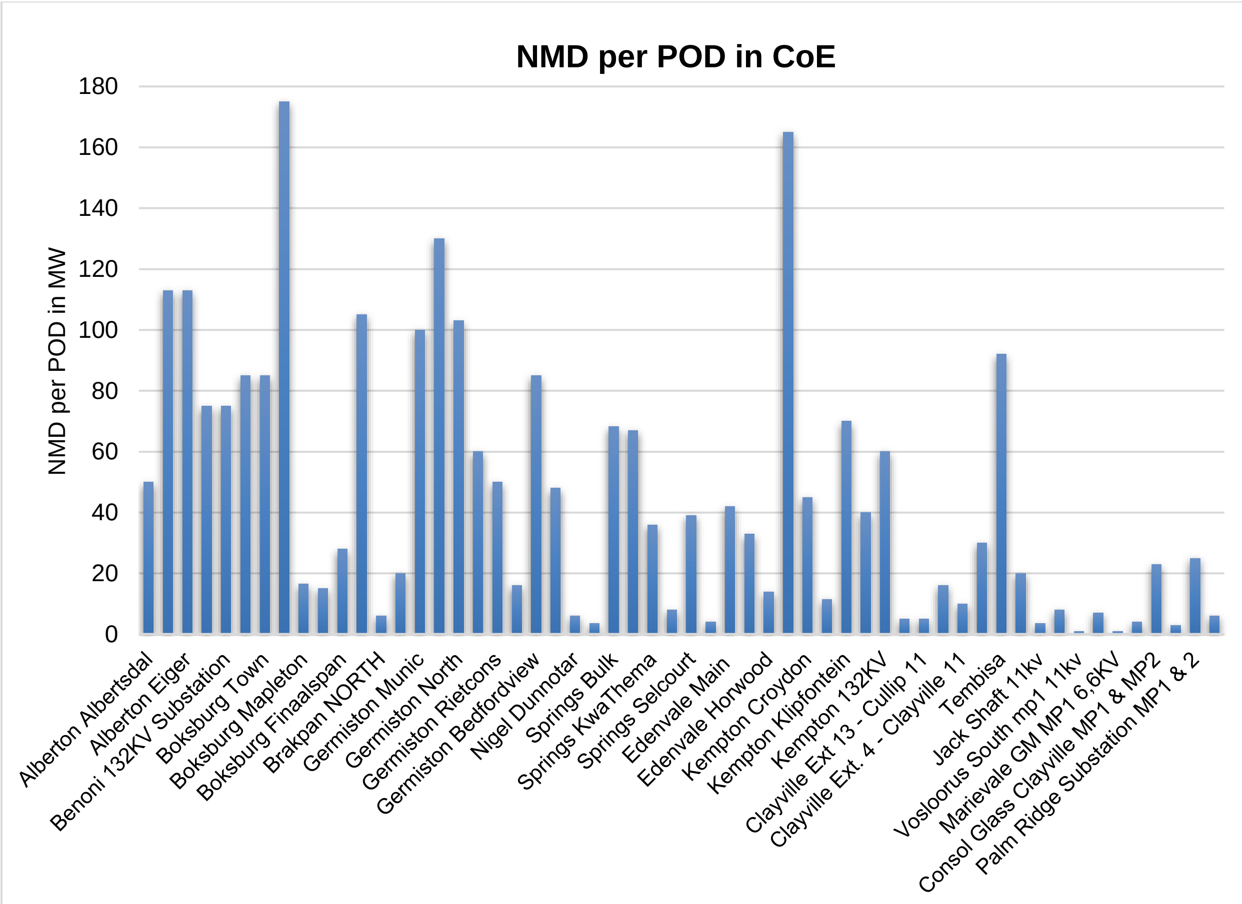

Figure 4.3: Different PODs and their NMD (in MW). (Source: Adopted from CoE eVenus system)

Figure 4.4 shows the NMD-share of each of the nine town areas of CoE, with Germiston at the highest level and Brakpan at the lowest. With reference to the key drivers of demand, the townships whose locations are shown in Figure 4.1 can be characterised as follows:

- Germiston, Boksburg, and Kempton Park together form what is called region A as categorised in the Regional Spatial Development Framework (RSDF) of the City of Ekurhuleni (EMM, 2012). Region A covers 13% of the total area of CoE with an area pf 24,795 hectares. The towns accommodate 150,000 households, that represent 17% of the households in CoE. The land use in the region includes mining, industrial and residential. Germiston has the highest NMD and is home to the Rand airport, heavy industries such as steel industries and smelters. Boksburg follows Germiston in the size of NMD, and it houses the Eastrand mall and some heavy industries. Commercial development is also occurring in the CBDs of all the three towns. Kempton Park is the third town in region A and is the home of the OR Tambo international Airport, as well as other industries.

- Edenvale and Tembisa and a portion of Kempton Park are found in region B, as described in the RSDF. The region has 244,000 households. Economic activities in this region include finance, mining and agriculture.
- Alberton is a town in region F and is surrounded by smaller townships, such as Thokoza, Katlehong and Vosloorus. The surrounding townships are supplied electricity by Eskom, whereas Alberton is supplied by CoE. The economic activities in this region include mining and the presence of an agricultural hub as well as several tourism sites and industries.
- Benoni, Brakpan and Springs form region D. This region is home to 233,000 households. The economic activities include finance, which is the largest employer and industries located in the periphery of the region, especially in Brakpan and Springs.
- Nigel is found in region E, together with Eskom-supplied surrounding areas such as Tsakane, Duduza and Kwa-Thema. Nigel is home to Dunnotar airport and a military base, with industrial developments mushrooming around Springs. Other economic activities include mining although most of the mines are no longer active.

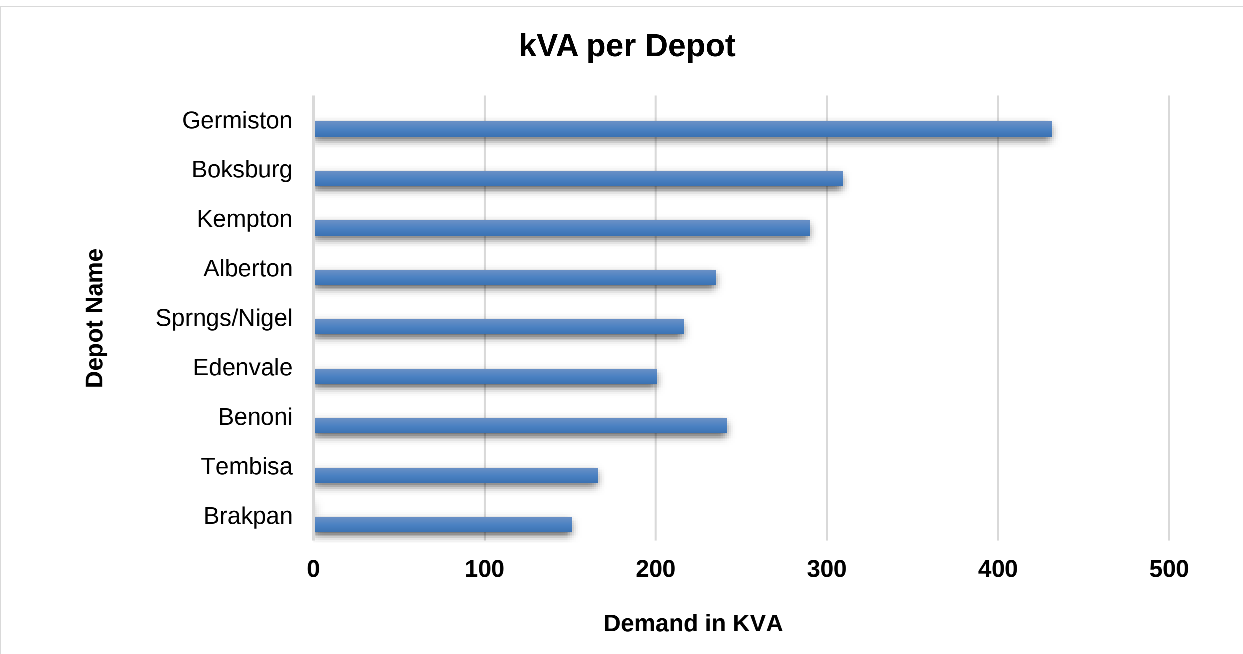

Figure 4.4: The different NMDs for each town of CoE.(Source: Adopted from CoE eVenus system)

Figure 4.5 shows the breakdown of the percentage of energy consumption in each town of CoE. Given that the highest demand is recorded for Germiston followed by Boksburg and Kempton Park, the energy consumption (in kWh) for each town should generally follow the same pattern as that of the NMD-levels. This is reflected in the consumption levels shown in Figure 4.5.

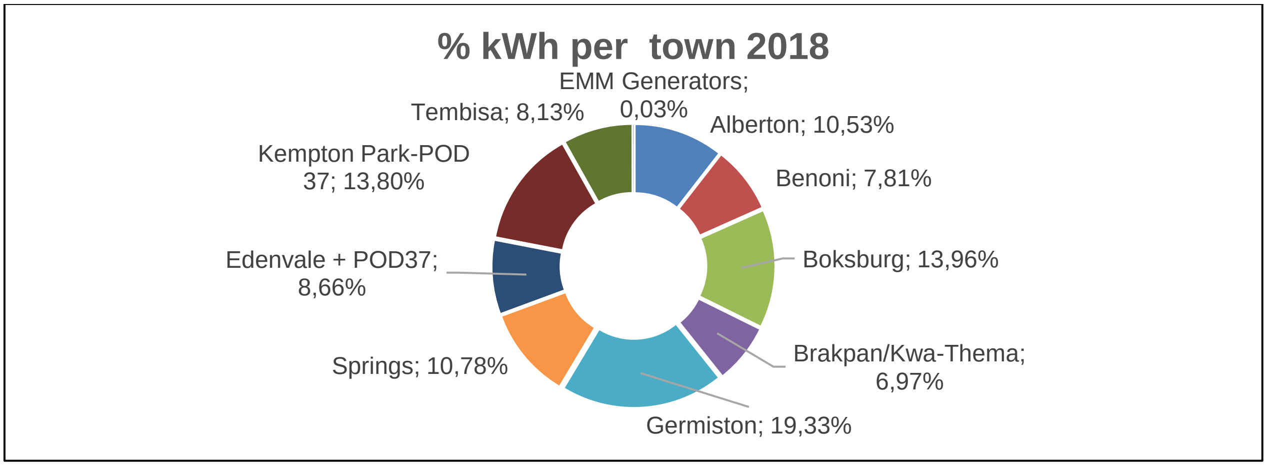

Figure 4.5: Percentage of electricity consumption per town for 2018 (Source: CoE eVenus system).

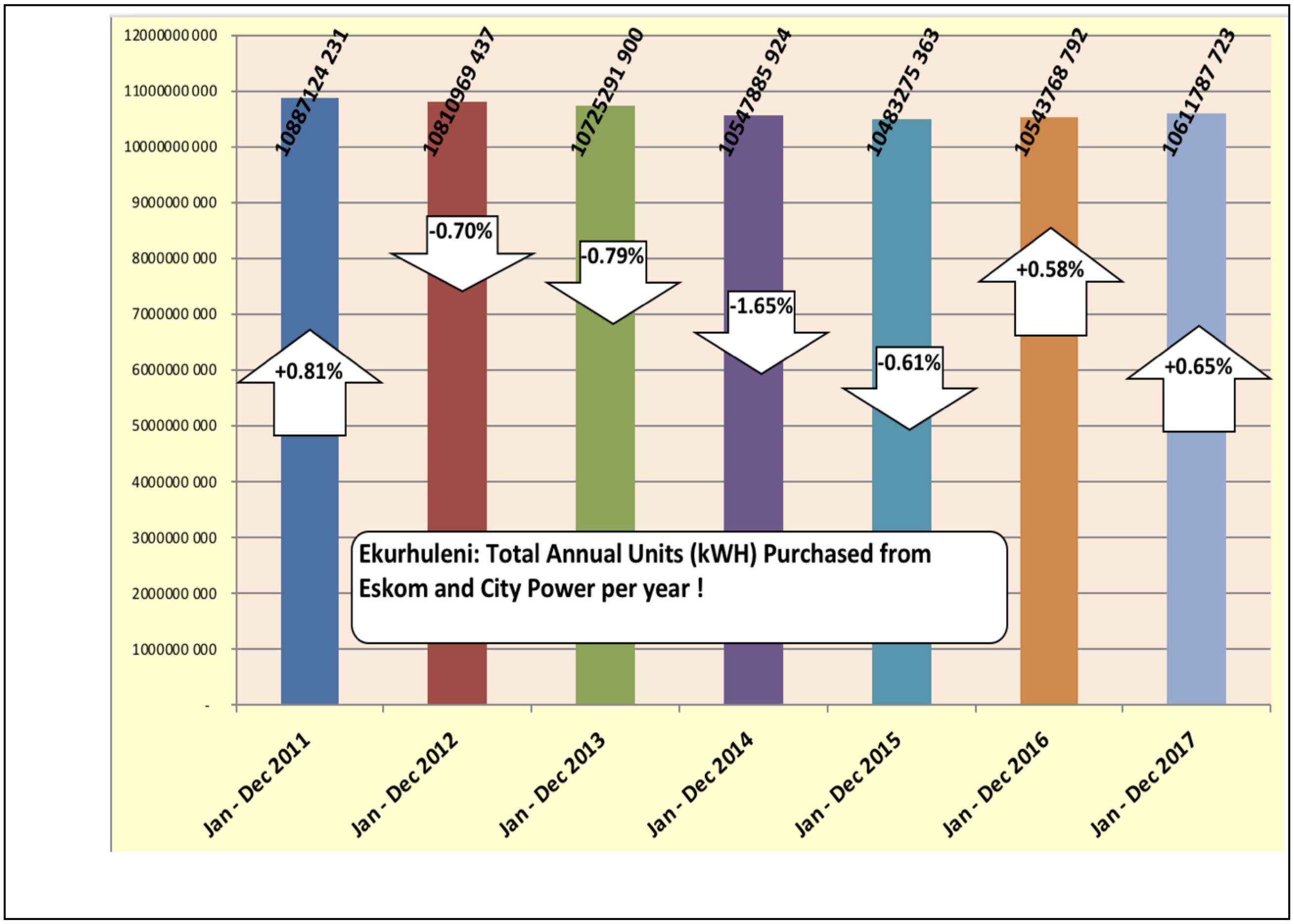

Figure 4.6: Graphical representation of the movement of purchases in calendar years from 2011 to 2017 (Source: CoE eVenus system)

Figure 4.6 above shows an analysis of the kWh purchases from Eskom for each calendar year between 2011 to 2017. The complete data set of purchases for the study period covering 2009 and 2018 are presented in Table 4.1. Based on the data, 2016 and 2017 showed roughly 0.58% and 0.65% year on year increase respectively. From the calendar-year-sales, there is no definitive evidence of electricity sales growth over the period yet, even though some fluctuations are evident in both directions.

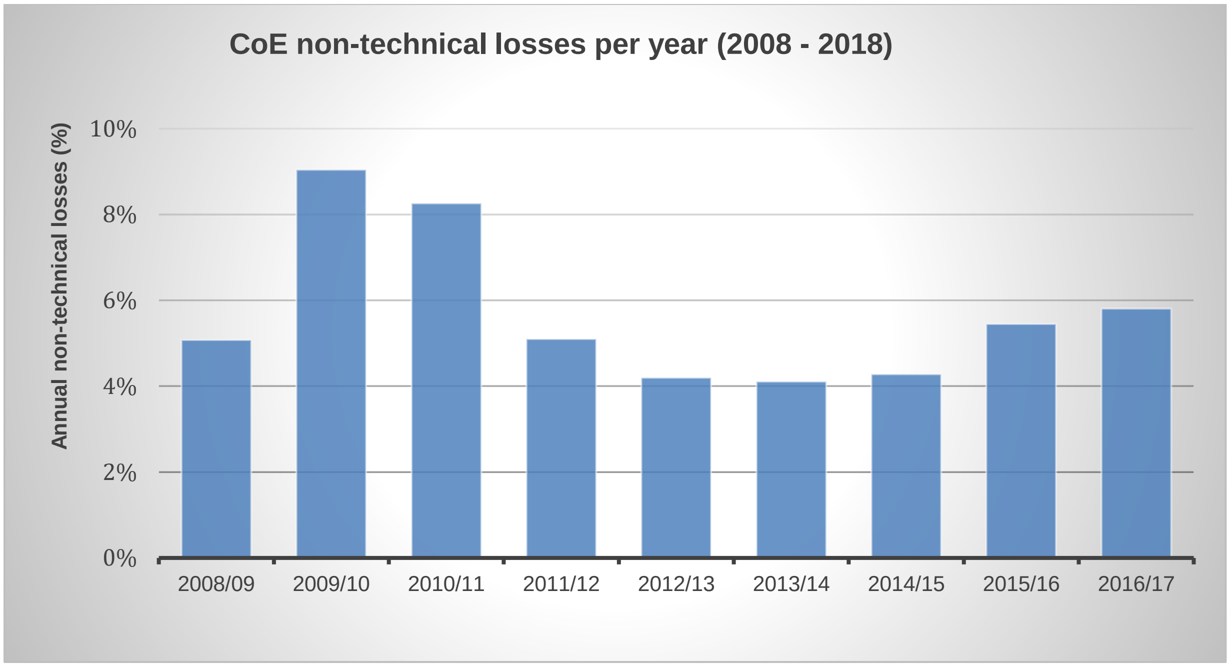

Figure 4.7: Trend of non-technical losses for CoE for financial years 2008/09 to 2017/18 (Source: CoE eVenus system).

Figure 4.7 shows the non-technical losses of CoE for financial periods between 2008/09 and 2017/18. There was a sustained decline in losses from a peak of 9.04% in 2009/10 to a low of 4.11% in 2013/14. However, there has been a significant deterioration from the 2015/16 financial year onwards, without any signs of improving. The increase in non-technical losses could possibly be due to illegal connections and meter tampering. This reflects avoidable revenue losses that could have been utilised to fund the growing costs of network operations.

TLs are a technical consequence of the transfer of electricity over the network. They occur over all parts of the network and vary with voltage, line length, conductor size and the amount of power being transferred. Technical losses form most of the total reconciliation losses, and while they cannot be measured directly, they can be estimated to a high level of accuracy through mathematical analysis and computer modelling of network performance. Technical losses arising from the supply of electricity to consumers directly connected at high voltage are lower than those incurred in supplying electricity to consumers connected to the low voltage network. Technical losses were assumed to be around 5.9% based on the secondary data accessed from CoE. However, CoE is currently conducting a more detailed study to determine the TL level more accurately. This study according to the interviewed municipal official, is mostly a desktop analysis based on complex engineering algorithm (Digisilent) which would help to determine the TL per depot and per Eskom POD given the unique loads at every depot and PODs (business, industrial, high end-residential/low-end residential).

4.5.2 Revenue performance trend for CoE

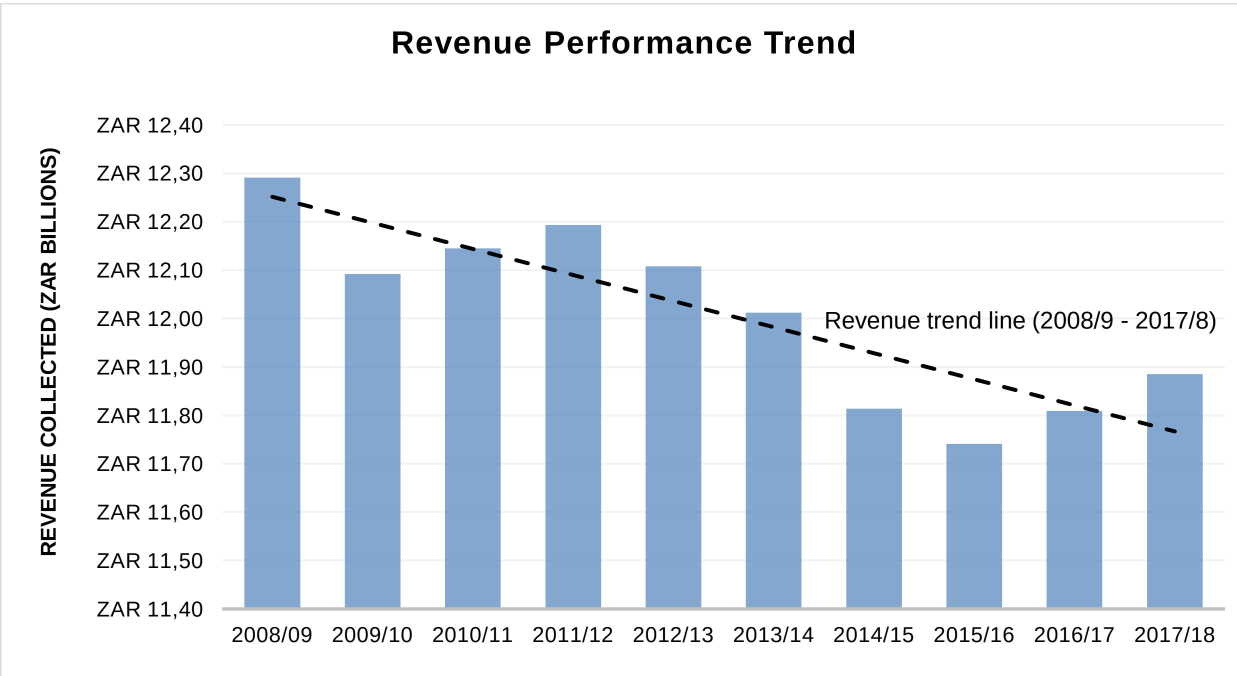

Figure 4.8: Revenue performance trend for the 10 years 2008/09-2017/18 (Source CoE eVenus system).

The revenue performance for the CoE under business-as-usual shows a general downward trend (dashed black line) based on figures from 2008/09 to 2017/18. The revenue performance is declining despite increasing electricity prices. The decline might be attributed to various drivers such as increased adoption of distributed PV generation by customers, thereby reducing their dependence on supplies from the grid and escalation in non-technical losses due to vandalism of infrastructure, manipulations of meters and non-payment for supplies. The declining trend reflects that tariff increases have not been able to offset the negative impact on revenue of the various drivers of NTL. Further, new residents that have significantly contributed to CoE's rapid population growth have been settling in informal settlements without access to electricity.

An interview-respondent from the municipal utility (see Appendix O) indicated that CoE is fully aware of the dangers of continuing with the business-as-usual approach. Even though it is increasingly aware of the fluctuations in energy sales, no assessments have been undertaken to quantify the fluctuation attributable to distributed PV generation. This concern over revenue erosion was further supported by the industry expert respondent, who expects further revenue losses not only from distributed PV generation but from all other sources of renewable energy.

Guided by the envisaged NERSA requirements, a process of registering SSEG is in place and it entails a formal application by owners/developers of the SSEG system. CoE records show that more than 30MW of SSEG projects have already been registered, accounting for 1.2% of the total capacity. CoE is also aware that the data collected on installed SSEG do not include all installations, as many project owners have not yet registered their projects. There is, therefore, a need for CoE to further raise awareness on the importance of registering and thus encourage registration of SSEG.

A responsive initiative is underway to capture most projects throughout the City. Through a municipal procurement process, the City has initiated a Localized Renewable Energy Independent Power Producers (LREIPP) program whose implementation is awaiting a ministerial determination from the Minister of the Department of Energy (DoE). The aim of the localised REIPP program is to procure energy from the private sector at rates that are less than Eskom's. The intention is to ensure that the City procures electricity that has a lower LCOE compared to grid electricity. This would save the City significant financial resources on the purchase costs of electricity. The program would assist in reducing costs related to energy purchase-cost due to a lower LCOE of PV generation systems.

4.5.3 Impact on Business Model

From OUTA's perspective (see Appendix N for full transcript), the ongoing transition in the energy sector is unavoidable. The adoption of distributed rooftop PV is growing due to lover equipment cost and declining LCOE of PV systems. According to OUTA "Municipalities and Eskom must adapt to this transition and relook their business models". As the industry regulator, NERSA also needs to be ahead of the industry. This is not the case currently as it still lags behind the rapidly evolving developments. The current regulatory framework does not advance this transition as NERSA still uses a benchmarking system referenced to Eskom to determine tariff increases for municipal power utilities. It does not consider the alternative supply options now open for municipalities to explore.

Industry experts confirm that Eskom is also experiencing a decline in energy sales similar to the municipal power utilities mainly due to reduced generation, the slowing down in economic growth, as well as increasing SSEG. Eskom and municipal utilities, therefore, need to develop new business models to counteract this trend. NERSA also needs to implement a regulatory framework that provides leadership and direction in the evolution of the electricity generation and supply value chain. Industry experts view NERSA as lagging behind the industry transitioning currently underway.

An interview participant at NERSA (see Appendix P for full transcript) confirmed NERSA has already started to show proactiveness and recognition of the changes in the industry by requiring power utilities to conduct CoS studies that should take into consideration all costs that are deemed to be prudent (and also exclude costs that are not prudent) for revenue recovery. NERSA also has processes in place to incentivise operational efficiencies of municipal power utilities.

Based on the responses from the interviews with industry experts (see Appendix M for a full transcript), the so-called “death spiral” is imminent in the electricity-sector should power utilities continue with their business-as-usual approach. According to the responses from interview participants, power utilities need to transform into service industry instead of only relying on sales of electricity as a commodity. Decentralisation of energy systems should be considered and pursued by various stakeholders. Embedded generation, specifically through distributed rooftop PV, should be embraced and leveraged towards inclusive development for South African cities. Municipal power utilities should, therefore, be proactively championing the transition to cushion themselves from the expected negative impact while also facilitating sustainable transitioning for their respective cities.

5 PREVAILING REVENUE EROSION UNDER DISTRIBUTED PV GENERATION AND POSSIBLE MITIGATING STRATEGIES

5.1 Introduction

This chapter presents the data and analyses on municipal revenue erosion arising from distributed PV generation. The analysis focuses on the current erosion and projected trends, should the CoE continue with its business-as-usual approach. The chapter then provides some insights into possible ways of addressing this erosion, thereby building a framework towards the conceptualisation of a responsive business model as presented in Chapter 6.

5.2 Presentation and Analysis of the Data

5.2.1 LCOE PV versus grid electricity

Year	Eskom average grid cost (c/kWh)	Reported LCOE PV(c/kWh)	CoE average grid cost (c/kWh)
2010	38.2		74.8
2011	48	365	92
2012	56.8	218	100.2
2013	62.24	117	100.09
2014	67.33	87	100.16
2015	74.75	65	129
2016	82.68	not available	137.4
2017	89.1	not available	135.4

Table 5.1: Grid electricity cost versus the LCOE of PV (Source: Calitz et al., 2017; CoE, 2017).

Table 5.1 shows the grid cost for Eskom and CoE as well as the reported PV LCOE. Note that CoE margins and other related costs factored into the tariffs increases the grid cost of electricity supplied by Eskom, thus increasing the respective LCOE. As a result, grid parity was reached earlier than 2015 for CoE.

5.2.2 Customer Data

Table 5.2 shows customer data collected for the different customer categories of CoE municipal utility. A total of 427,500 customers are served by the municipal utility (which include residential, commercial and industrial).

Customer Group	Number of customers
Large customers	8,500
Prepaid	275,000
IMMS (Intelligent Meter Management System)	44,000
Conventional Meters	100,000
Total	**427,500**

Table 5.2: Secondary data on CoE customers (CoE eVenus system).

5.2.3 SSEG growth trend for CoE

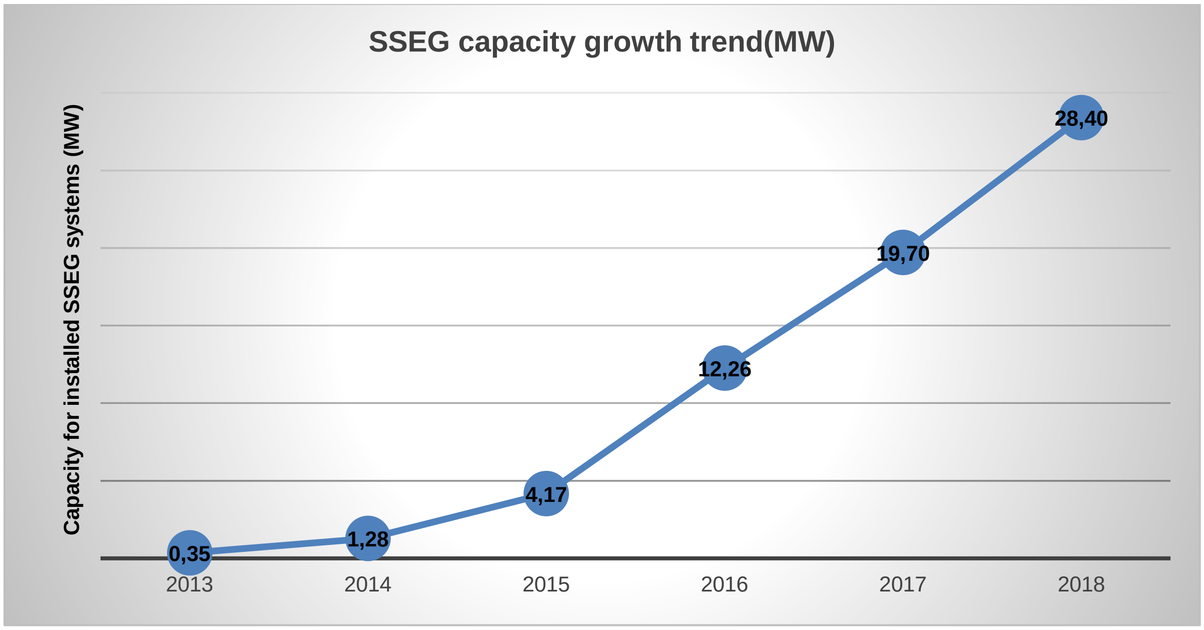

Figure 5.1: The SSEG trend based on reported and registered PV systems.

Figure 5.1 shows the current trend of registered SSEG plants in CoE and does not include installations that are not registered with CoE. This shows an increasing penetration of distributed PV in the city where the recorded installations were at 28.40 MW in 2018. Currently, there is no by-law or any other national regulation that require project owners to register their installations with the city. As a result, the numbers presented in Figure 5.1 do not reflect an accurate number of the installed capacity. However, registration is expected to become compulsory once the SSEG registration rules are finalised and promulgated by NERSA. Within this regulatory vacuum, CoE has been pro-active in developing the application forms coupled with the standardisation of connection requirements for SSEG systems/technologies. This study has verified the reported systems as installed and operational. The verification process, which included site visits, shows the reality of the increased diffusion/adoption of distributed PV.

The NREL PVWatts calculator (NREL,2015, http://pvwatts.nrel.gov) which uses the solar resource data of the selected sites, was used for estimating the possible electricity-generation that can be produced by a 28 MW solar PV system in CoE annually. Table 5.3 shows the derived monthly generation for the 2018 installed capacity.

MONTH	Solar Radiation (kWh/m²/day	AC Energy (kWh)
January	6.26	4,106,714
February	5.58	3,361,604
March	4.88	3,219,532
April	3.67	2,374,764
May	2.71	1,716,288
June	2.21	1,336,375
July	2.47	1,565,360
August	3.39	2,238,198
September	4.45	2,889,323
October	5.43	3,689,544
November	5.94	3,897,722
December	6.55	4,397,963
ANNUAL	**4.46**	**34,793,387**

Table 5.3: NREL PV Watts calculated energy output for a 28MW PV system.

The total registered capacity of distributed PV is currently measured at 1.2% of CoE's NMD and the calculated energy that can be produced, as calculated using the NREL software, is 34,793,387 kWh. This represents 0.32% of the annual energy purchased from Eskom. This figure appears small in percentage terms, but it translates to R30 million per annum worth of energy that could have been purchased from Eskom and resold at a margin. Using the available tariff data (CoE, 2018), a single kWh is sold for average CoE tariff of R1.30 at 2018 rates.

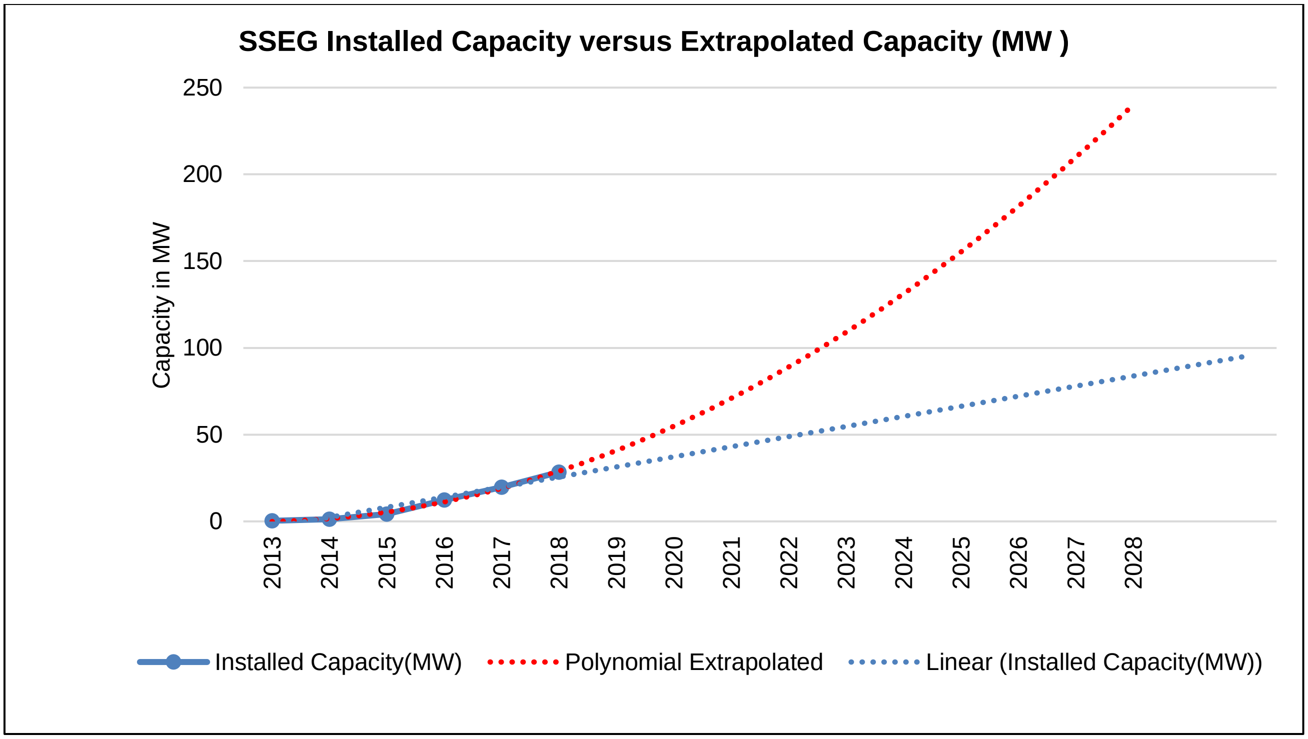

Figure 5.2: Linear versus polynomial extrapolated growth trend for SSEG to 2028.

The extrapolation in Figure 5.2 shows the capacity of distributed PV approaching 250 MW by 2028. This translates to 310 million kWh/a, and a drop in revenue of about 3% on the 2017/18 revenue figure or absolute revenue loss of R403 million per year. It is important to note that the extrapolation was done based on the available data on registered systems. It is known that not all systems are registered, and it is therefore correct to conclude that the projected revenue loss figure would be higher than 3%. This projected growth is likely to increase in response to the increasing electricity tariffs and a further decline in LCOE for PV.

5.2.4 LCOE PV versus Grid Price

Data relating to grid electricity costs and PV LCOE were analysed and plotted, as shown in Figure 5.3.

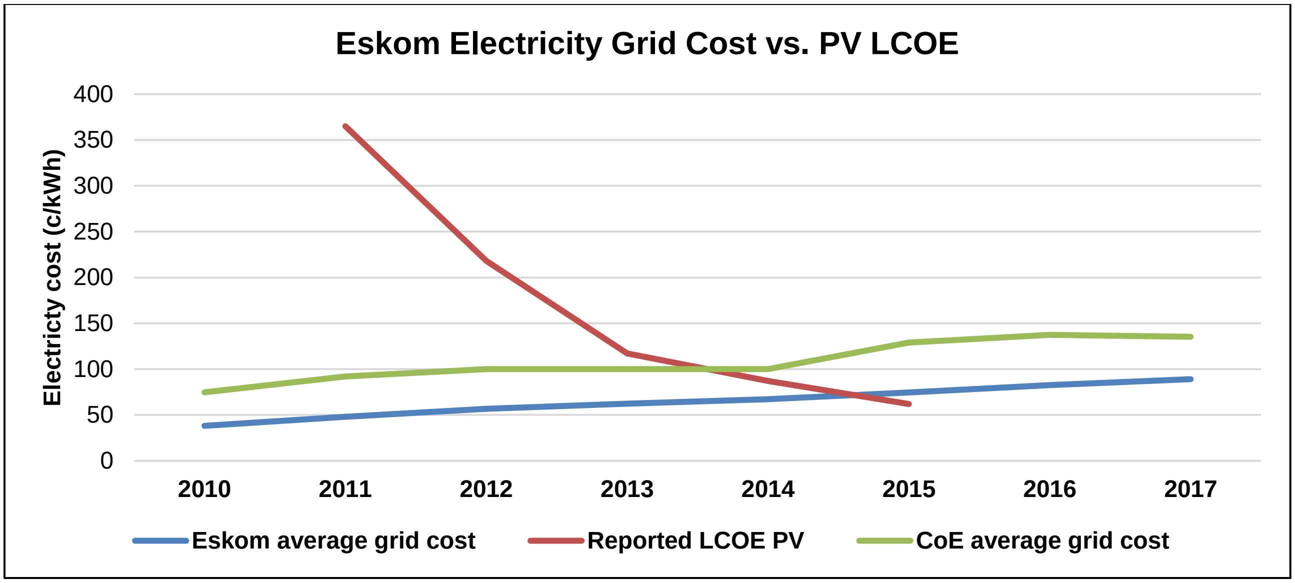

Figure 5.3: Analysis of grid electricity prices versus the LCOE PV (Source : Adopted from Calitz et al.,2017, CoE eVenus system).

The data shows the trend over the period from 2011 to 2018. The blue line shows the Eskom's average cost of electricity to CoE and the orange line shows the levelised cost of electricity generated from PV. The point at which the lines cross is the point at which grid parity occurs. Based on the graph PV LCOE versus Eskom, average grid cost reached grid-parity somewhere between 2014 and 2015 and has since been falling further below grid LCOE. Given that this trend is expected to continue, it will become increasingly financially beneficial for CoE to purchase more energy from grid-connected distributed PV rather than from Eskom. However, from a municipal customer's perspective, PV LCOE reached grid-parity (CoE grid-LCOE) earlier (possibly between 2013 and 2014, as indicated in Figure 5.3).

5.3 Estimating the Maximum Percentage of PV Penetration (SSEG modelling)

The maximum possible revenue erosion scenario is modelled around the number of customers, customer category and the likelihood of each customer-category to invest in a grid-connected distributed PV. From the customer data collected and presented in the preceding section, CoE has 8,500 commercial and industrial customers. CoE's major concern is that it derives 60% of its revenue from these customers and is thus exposed to concentration risk. The secondary data presented shows that the total NMD for large customers adds to a total of 1,376MVA.CoE has conducted a CoS study to fulfil NERSA's requirement (CoE, 2018). This study included SSEG modelling and reached a finding that the increase in PV penetration results in revenue loss as well as a reduction in bulk purchases. The effect on bulk purchases is greater than the actual revenue loss, and this is because of the technical losses that are incurred when transmitting the energy. The increase in PV penetration has a positive effect on technical losses, which results in a decrease in losses attributable to improved generation and transmission efficiencies for own generated energy.

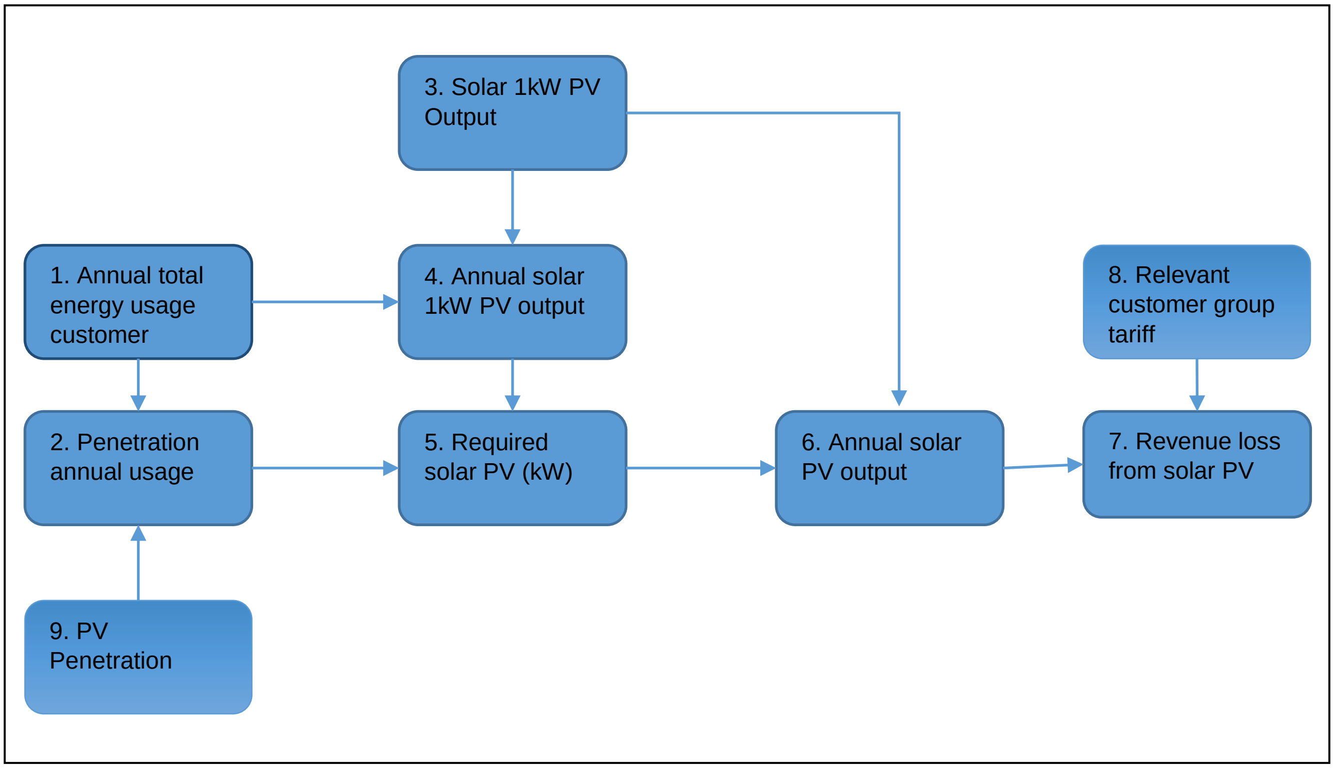

Figure 5.4: Solar PV (SSEG) revenue impact calculation process flowchart (CoE, 2018 page 40).

Figure 5.4 shows the process of estimating the total revenue loss from solar PV as applied in CoS study for CoE. This process is similar to that described and utilised by Korsten et al. (2017) for establishing the impact of distributed PV. The relevant groups of customers that are likely to install rooftop PV are the commercial and industrial customers, as well as middle to high-income residential customers. The indigent group is unlikely to install these systems and, as a result, are excluded from the calculations. The indigent customer group is considered a vulnerable group and is defined as customers who earn anything between R0.00 to R3,500 per month (CoE, 206). Another group of customers that will be excluded are the customers in complexes and resellers.

According to Cai et al. (2013), the likelihood that any customer will install rooftop PV increases with the resultant reduction of the customer's bill as facilitated by a distributed generation with the installation of PV systems.

An energy modelling process was conducted using a freely available software called PV Watts (Stark *et al*, 2015), which uses satellite solar radiation data for the area or location of the proposed system and the installed peak capacity of the system to perform a yield assessment for power generation on the site based on meteorological data. Based on the estimation process, the major customers would have a combined installed capacity of 1,376 MW; this is 55.05% of the current total installed capacity. It was assumed that this is the total capacity that these customers would consider installing for the purpose of running their own operations. It should also be noted that this is the customers' maximum daytime demand, which can be supplied through PV but does not necessarily mean the customers would be completely off the grid (the customer would continue being connected to the grid). However, customers with processes that run entirely during the day stand to benefit the most. In contrast, customers with huge power demand after sunset would still largely depend on grid power but also have the option of installing storage systems. At certain times, the customer might generate excess power, which could be fed into the grid. However, the CoE currently does not have a framework to address this scenario, which thus results in the customers feeding into the CoE grid without compensation. The total annual energy generation (kWh) for the 1,376MVA, as calculated through NREL's PVWatts software, is 1,709,846,310 kWh/year. Table 5.4 below shows the geographical data for CoE's location. This alone would translate into about 19% possible revenue loss annually (and about R2.2 billion in absolute terms).

MONTH	Solar Radiation (kwh/m²/day	AC Energy (kWh)
January	6.26	201,815,660.00
February	5.58	165,198,810.00
March	4.88	158,216,900.00
April	3.67	116,702,750.00

May	2.71	84,343,230.00
June	2.21	65,673,340.00
July	2.47	76,926,260.00
August	3.39	109,991,350.00
September	4.45	141,989,630.00
October	5.43	181,314,720.00
November	5.94	191,545,200.00
December	6.55	216,128,460.00
ANNUAL	**4.46**	**1,709,846,310.00**

Table 5.4: Estimated energy output figures based on NREL's PV Watts software (Source: http://www.nrel.gov.).

Resellers purchase electricity in bulk from CoE for the sole purpose of reselling mostly within building complexes and estates. These customers do not pose a risk of revenue loss due to distributed PV as they do not have a strong incentive to avoid the cost.

CoE has 427,000 customers in total (see Table 5.2). However, it is highly unlikely for the indigent customer group will implement rooftop PV, and as a result, the group is removed from the total number. The indigent number is currently 102,000 households (CoE, 2018), which leaves 317,000 customers (excluding the large customers) who are likely to consider rooftop PV. If all customers were to theoretically install 3kVA system (Korsten et al.,2019:36), totalling 951MVA. The energy yield for these systems combined is 1,181,732,320 kWh annually (PVWatts.NREL.gov). This energy translates into 11.13% revenue loss for the City or R1.536 billion. The total estimated loss comes to 30.13% of annual sales. Based on the current average electricity cost of R1.30c/kWh, this equates to about R3.736 billion in revenue loss annually. This scenario is based on real customer numbers and their current NMD.

5.4 Findings: Critical Parameters in Electricity Revenue Performance

5.4.1 The significance of LCOE

The electricity distribution value chain starts with the generation of electricity. This stage in the value chain has its own costs that vary according to related technologies and primary energy sources employed. Currently, Eskom is the main national generator and supplier to CoE, who then distribute the electricity at a margin above cost. CoE procures this electricity at a final or consolidated cost, which includes all costs associated with generation and transmission, as well as a regulated margin for Eskom. This price at which CoE procures Eskom-supplied electricity can be equated to the LCOE for the electricity from the grid.

On the other hand, the LCOE for PV in South Africa in 2015 was at R0.65/kWh compared to grid electricity (Eskom) LCOE at R0.75/kWh and CoE grid-LCOE at R1.29/kWh (see Table 5.1). This shows that the LCOE for PV has already gone below grid parity and electricity generated from PV is now cheaper for the consumer compared to grid electricity. The municipal utility would be enhancing its own profitability by procuring electricity generated from PV sources instead of grid electricity.

Location	**System type**	**System capacity(kW)**
OR Tambo precinct (2012)	Ground Mounted PV	200
Springs Civic centre (2014)	Rooftop PV	250
Alberton Civic Centre (2017)	Rooftop PV	500
Kempton Park civic centre	Rooftop PV	750
Boksburg civic center (2016)	Rooftop PV	250
Landfill Gas to electricity (2014)	LFG	1000

Total		**2,950**

Table 5.5: Completed municipal-owned RE projects (Source: eVenus system).

CoE has also initiated a localised Renewable Energy Independent Power Producer (REIPP) program that involves the CoE procuring electricity from REIPP at costs lower than the LCOE of grid electricity. The program aims to source 683 MW from various renewable energy sources, such as PV, waste to energy, and gas. CoE can prioritise rooftop PV as it has already reached grid parity and the LCOE continues to drop below grid electricity costs. The impact of this will be improved CoE profit margins. The location of these localized REIPP projects within the licensed municipal supply area will also reduce technical losses related to Eskom's transmission and possibly on distribution to customers. Data collected in this study shows that CoE has already initiated multiple grid connected distributed PV systems installations on most roofs of municipal buildings.

Table 5.5 shows data collected on the renewable energy projects the City has already implemented. Evidence of the municipal-owned rooftop PV installation program is currently visible with the installation on the Alberton Civic Centre (see Figure 5.5, Figure 5.6 and Figure 5.8). The system installed is 500kWp and provides power to the Alberton building, as well as allowing export of surplus power back into the municipal grid. It further shows the maximum installed capacity of each project and its corresponding technology. The combined total installed capacity is 2.95 MW. The benefits associated with these installations include the low LCOE of distributed PV translating into financial savings on electricity purchases. The Figures 5.9 to 5.10 show the load profile charts recorded for the Alberton civic center, and Figure 5.11 showing the net effect of the rooftop PV system in lowering the demand on the grid.

Figure 5.5: Rooftop PV, 500kW installed on the Alberton Civic Centre Ekurhuleni. 20 February 2018

Figure 5.6: A closer caption of the Alberton Civic Centre rooftop PV, 500kWp system. 20 February 2018.

Figure 5.7: A different angle view of Alberton Civic Centre rooftop PV .20 February 2018.

Figure 5.8: Aerial view of the Kempton Park Civic Centre showing the installed rooftop PV system.25 February 2018.

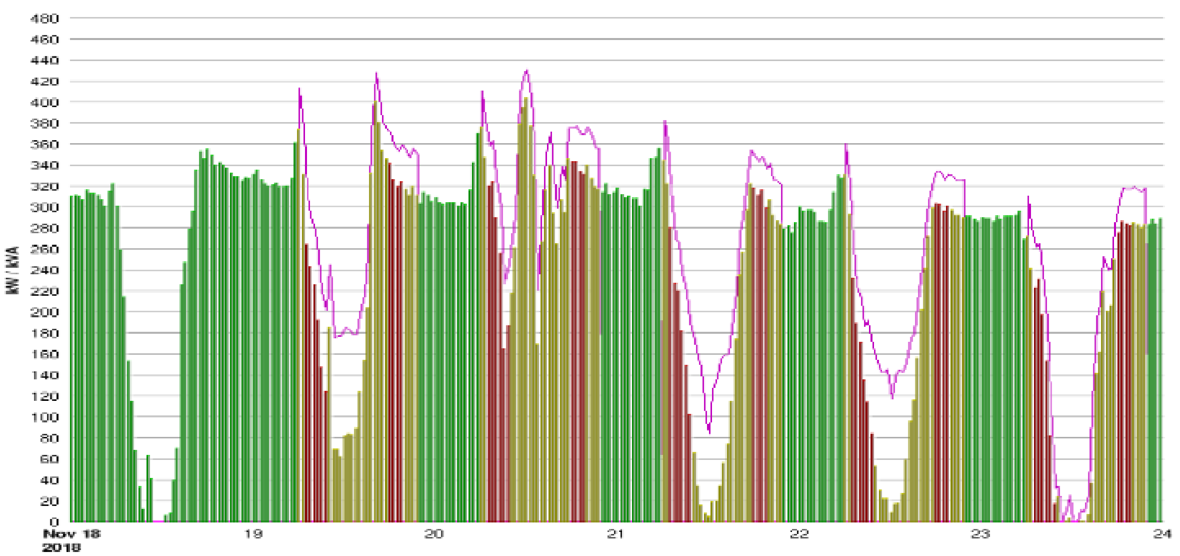

Figure 5.9: Load profile chart for Alberton Civic Centre (Source: CoE Metering on-Line system,One-week load profile 18 November (Sunday) to 24 November (Saturday) 2018.

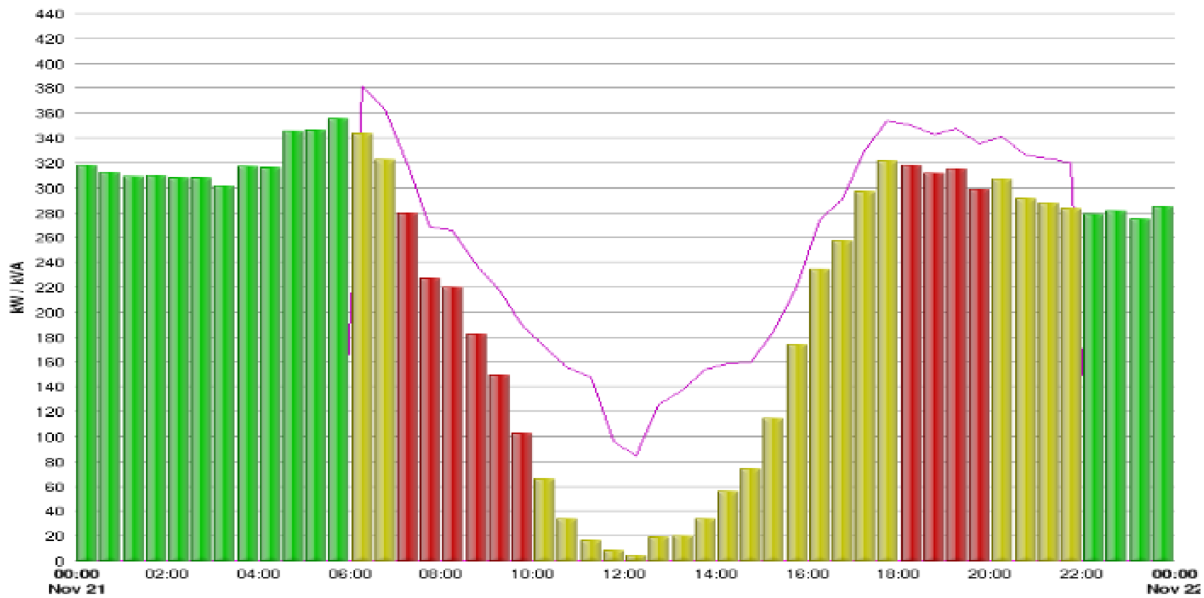

Figure 5.10: Alberton Civic Centre load profile (Source: CoE metering on-line system). Load profile (normal working day) (21 November 2018).

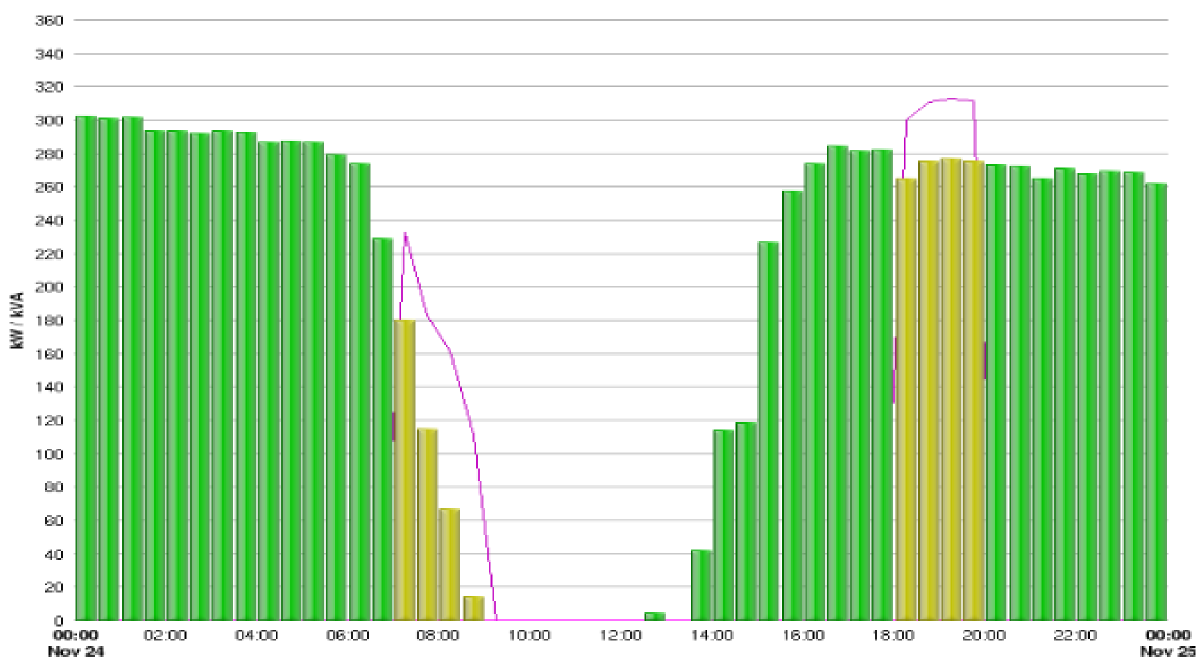

Figure 5.11: Effect of the rooftop PV system in lowering the demand on the grid (Source: CoE metering on-line system).

5.4.2 Operational Efficiencies

Operational efficiencies are already included as variables in the calculation of CoS. These relate to improvements in loss mitigation performance for both technical and non-technical losses, energy efficiency, and the management of demand from both the supply side and the customer's side. In 2017/18, CoE lost R1.027 billion, of which R511 million was due to NTL (CoE, 2018) and with the balance being TL. CoE could save a portion of these amounts through the implementation of energy efficiency programs on municipal infrastructure. The implementation of energy efficiency also has economic and social benefits beyond the expected energy savings. Energy Efficiency and Demand Side Management (EEDSM) projects on municipal infrastructure, such as those currently funded by the national Department of Energy (DoE) have been and continue to be implemented in CoE, resulting in huge financial benefits. The initiatives include retrofitting of municipal buildings with LED lights, installation of solar water heating, and a municipal-owned SSEG program on municipal rooftops, as well as LED streetlights. Figures 5.5 to 5.7 show the 500 kW rooftop PV system installed on the roof of the Alberton civic centre, which is part of energy efficiency and demand-side management initiatives by CoE. The implementation EEDSM initiatives such as those shown in fig 5.5 to 5.7 improve the operational efficiency of CoE due to a lower LCOE of PV.

6 TOWARDS A RESPONSIVE BUSINESS MODEL FOR MUNICIPAL POWER UTILITIES

6.1 Introduction

This chapter presents a consolidation of insights and findings from Chapters 4 and 5 in order to derive the resolution to the main research question on a responsive business model that would safeguard municipal revenue within increased distributed PV generation scenario. The chapter, therefore, presents the conceptualisation and formulation of the proposed/envisaged business model derived using the applicable BMC tool. Municipal utilities must transform themselves from merely selling electricity as a commodity to fully being integrated energy solution utilities.

6.2 Business Modelling Innovation using BMC

The transition in the electricity sector is creating both challenges and opportunities that must be managed by utilities. The management of this transition can be done by developing and implementing new business models that would be responsive to the critical drivers of the transition. The BMC, as a recognised and tested tool, is utilised as a base platform upon which a new business model that is responsive is conceptualised through a combination of findings and insights from the study. The purpose of developing a new business model is to respond to the disruptions and pressures put on the current business model by the increased distributed PV penetration, which is rapidly rendering the prevailing model municipal power utility unsustainable.

Key Partners:	**Key Activities**:	**Value Proposition**:	**Customer Relationships**:	**Customer segments**:
• Eskom SOC • internet service providers • Third-party vendors/retailer • OEMs • Service Providers/ESCos • NERSA • Independent Power producers • SSEGs • prosumers	• Access/ Procure electricity. • Improve efficiencies in the operating & maintaining electricity distribution network. • Generate electricity • Resell electricity • Distribution platform operator	• Provide cheaper/affordable and cleaner electricity through various delivery mechanisms • Facilitation of supply and installation of distributed PV generation systems on customer premises. • RE credits	• Online presence • Customer forums • Captive customers due to the regulatory structure of the sector	• Residential customers • Industrial customers and; • Commercial customers
	Key Resources • CoE owned plants		**Channels**: • Municipal owned embedded generation on	

	• The digitalisation of network (smart systems) • Vehicles • Human resources • Financing		customer premises. • Wheeling arrangements • Net metering	

<u>Cost Structure</u>: • Electricity purchases • Maintenance costs • Operational costs • Free 100kWh • Network modernisation and digitalisation (Smart grid) • Losses	**<u>Revenue Streams:</u>** • Rate structure reform • Continue with CoS but explore more sources of income • Implementation of distributed PV • Access to lower LCOE has a positive impact on revenue • Decoupling mechanism (revenue and sales) • Wheeling charges • Operational efficiencies • Alternative Revenue streams and other energy initiatives, such as gas

Table 6.1: The proposed municipal power utility business model mapped using the BMC
(adapted from Osterwalder and Pigneur 2010).

6.2.1 Customer Segments

The innovation technique starts by asking a question that relates to the challenges that will be faced by municipal power utilities when the different customer segments start generating their own electricity through distributed PV generation. CoE, like all municipal power utilities in South Africa, has been delivering electricity to the different customer segments at rates based largely on consumer's usage. As previously discussed, this model threatens the viability and existence of the power utility unless an alternative business model is considered. CoE has three main categories of customers, and the large power users or LPUs comprise of industrial and commercial customers who contribute 60% to the municipal revenue. The remainder of the revenue is derived from the residential customer category, which has a special portion of customers called indigents. This customer group is the least user of electricity and comprises of low- or no-income earners who benefit more from low electricity prices and free basic electricity that is currently offered by the Government, amongst other grants.

6.2.2 Value Proposition

The value proposition in the proposed model suggests initially continuing with the provision of electricity through the current method of procuring electricity from Eskom. In addition, there are further opportunities for CoE to transition itself into a total energy solutions provider leveraging on partnerships with key stakeholders. CoE could thus become the centre of focus for clients and manages the various relationship with technical partners. In addition to that, procurement from IPPs and SSEGs would be introduced. One innovative opportunity would be the direct purchase of electricity by the utility from the generator. This would differ from the current arrangement where the municipal power utility procures from the Eskom distribution and then distributes to its consumers at a margin. The financing and installation of SSEGs on a customer's premises is a further innovation that would eliminate the capital burden for customers who would have installed their own systems. This option does open additional sites for CoE to generate electricity within its own jurisdiction. This study has shown that LCOE for PV has long dipped below grid parity, which means that purchasing directly from the PV generators would cost less than any other generator. Revenue would also be improved if municipal power utilities ensure a better balance in procuring directly from Eskom generation and other generators within their licensed areas instead of procuring solely from Eskom distribution. This would facilitate a reduced overall LCOE for CoE.

The current procurement structure is arranged such that municipal power utilities do not procure directly from Eskom generation.

Secondly, procuring green power from IPPs and SSEGs by CoE would provide an opportunity to measure, verify and issue green certificates to customers that might have value in the global markets. Also, the fact that the LCOE for PV has already surpassed grid parity provides the customers with access to lower eco-rates. These new services would ensure that both customers and municipal power utility become efficient in their operations and achieve savings. CoE would then have to market this service to its customers. This component of the model proposes that CoE initially prioritise the 8,500 large customers that pose the greatest risk of revenue loss. Through a service level agreement (SLA) with the customer, CoE should provide the services for the design, supply, installation, operation and maintenance of the rooftop PV system. This service would also ensure that rooftop PV systems are installed on the roofs of customers at no upfront cost to these customers and in compliance with relevant regulations, standards and specifications.

Financing mechanisms, such as leasing, might also be included as optional for customers to ultimately own the equipment after a predefined and agreed period. The role of key partners identified as ESCos and Financiers becomes relevant in the entire supply chain. The ESCos provide the technical know-how and implementation, whereas the financiers provide the necessary funding for the procurement of equipment and the installation. CoE can leverage on developmental institutions, such as the African Development Bank, which has set up a dedicated fund to promote renewable energy (the Sustainable Energy Fund for Africa -SEFA) and focuses on the provision of equity financing and technical advice for small scale projects ranging between 5 and 50 MW. The value proposition becomes the provision of “green power” at “eco-power” rates.

The power generated by the rooftop PV is metered, and a bill is generated for the customer. For installation purposes, a smart meter, which has four-quadrant capabilities, is required as it can measure consumption as well as the surplus power that is supplied into the municipal grid. A special tariff or “eco-power” rates would then take into consideration the beneficial effect of location on the customer’s roof, thus conferring loss-mitigation benefits compared to grid-supplied electricity. This innovation in the model would thus supply green power to customers (mainly commercial and industrial users), and the issuance of green certificates would enhance the attractiveness of this model. Currently, South Africa’s regulations limit self-generation installations to be equal-to or less-than 1 MW if the rigorous licensing process is to be adhered to. This means that all a project developer can either develop project less than 1MW or follow the rigorous licensing process for projects equal or bigger than 1MW.

The green certificate's sole purpose would be to provide verified confirmation of the amount of green power purchased by the customer and could be useful in instances, such as mitigating the impact of the carbon tax, which has already come into effect on 19 February 2019 (Duncan, 2019). The implementation of this component in the model would be geared towards mitigating the possible loss of revenue from the 8,500 large customers, which currently has been calculated to be in the region of 19% based on the total revenue of 2017/18 financial year. This component of the model has a second benefit attached to it, which is the reduction of bulk purchases from grid power and reduction of the associated technical losses (CoE, 2018). The third benefit of this component would be to ensure that the CoE can lock-in these customers through the provision of this service and thus enable the ongoing collection of accurate data that can be used for future revisions to the tariff structures, as well as the management and control of the municipal grid. Additional eco-power can be procured from SSEGs (mainly prosumers) at NERSA approved rates. The CoE would then have to develop the appropriate tariff structure for approval by NERSA before implementation.

6.2.3 Channels

The municipal power utility needs to provide the value proposition initially through the ordinary post-paid and prepaid methods which exist in the current business model. These methods involve billing for post-paid and procurement of vouchers for pre-paid. The proposed change to net-metering recognises and incentivises SSEGs. It could be used together with both the post-paid and pre-paid platforms with the added benefit of providing credits for surplus electricity generated by the customer. Wheeling arrangement would become a new the model that currently does not exist. This provides CoE the additional revenue opportunity generated from charging a generator for the transportation of their electricity to a dedicated customer located further away from the generation site. Several South African cities such as Nelson Mandela Bay and Tshwane municipalities have piloted this component for close to ten years (Mbatha, forthcoming).

6.2.4 Customer Relationships

The legislation and regulatory framework in South Africa give the municipal power utility authority to distribute and reticulate electricity in its area of jurisdiction. This means a municipal power utility cannot then distribute electricity outside its area of jurisdiction. Customers are therefore left with no choice of a preferred distributor. Customers must either subscribe to the municipal power utility or generate their own electricity (if own use is allowed). The power utility can, however, innovate to keep the customers by providing them with a value proposition that provides long-term contracts for providing renewable energy as a service without them investing in the capital costs. This will cause the customer to stay with the power utility and benefit financially from the savings shared by the utility. The financing, installation and maintenance of this value proposition are facilitated by the municipal utility though collaboration with key partners such as the DBSA and the African Development Bank (AfDB) for funding and the ESCos for implementation. This approach is attractive to all customer segments as it does not require an initial investment on their side. In order of priority, the municipal power utility could target the large customers whose interest in investing for self-generation through distributed PV technology are likely to increase as grid electricity tariffs rise.

6.2.5 Key Activities

There are two main activities in this model which are to gain access to electricity and reselling it to customers. In order to undertake these activities, the related sub-activities include options such as municipal-owned generation, procurement from Eskom at grid prices, procurement from IPPs and SSEGs at lower LCOE, and facilitation of RE installations on the customer’s side. These activities (IPP, net-metering and municipal owned generation) will ultimately result in Eskom selling less power to municipalities and therefore will not require to build new generation plants to meet demand. These innovations are well captured in Figure 6.1 which is adapted from the responses to the interview with SALGA, (see Appendix L for full transcript), the participant highlighted that the organisation had identified the three areas to be addressed (as listed below) when implementing new business models.

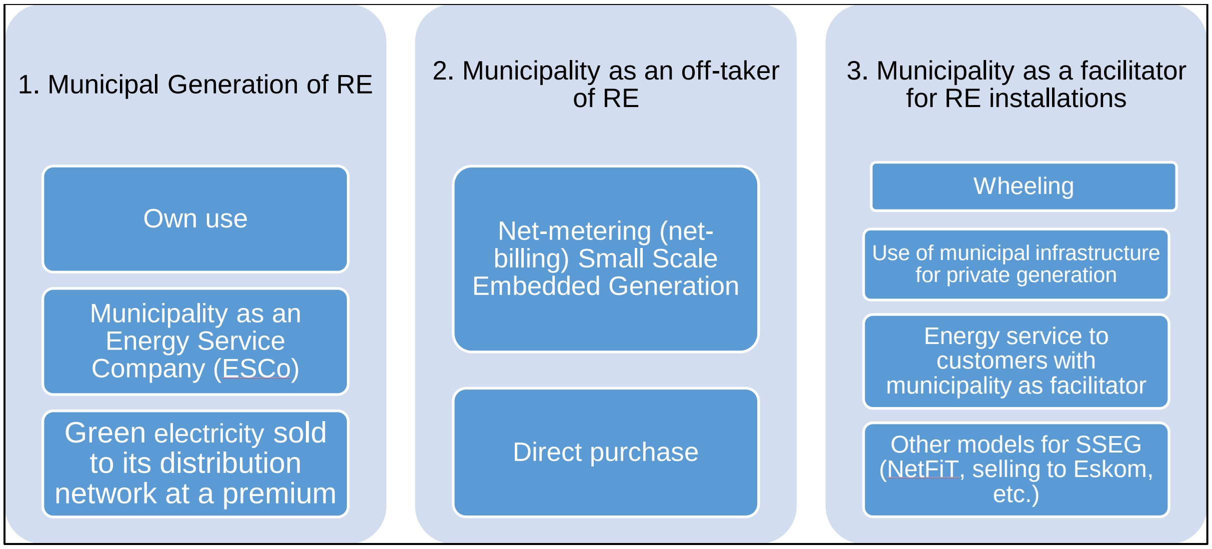

Figure 6.1: SALGA proposed components of new business models (Source: Adapted from interview with SALGA participant).

Other ancillary activities can be offered by CoE to provide a full bouquet of services thus allowing the utility to act as a central hub in the electricity market. It can enter into agreements with technical partners where they reside on CoE premises and be responsible for the provision of any technical services that might be required by consumers on alternative energy solutions. This gives the municipal utility additional lines of revenue generation from advisory fees and financing charges.

6.2.6 Key Resources

The key resources identified for the new model include the electricity generation and distribution network assets required for the physical production and delivery of the value proposition to the customer. In the mapped business model for municipal power, utilities must address the deficiencies in the human capital and capacity development to ensure that the aged and dilapidated infrastructure (that could constrain the take-up of the increasing distributed technologies) is enhanced and modernised. The digitalisation of the electricity distribution networks would come with improved efficiencies. The digitalisation of the network involves implementation of smart-grid technologies with the internet of things (IoT) as one of the key components.

CoE has already conducted a feasibility study on a smart grid approach, and it is geared towards a smart city future where the smart grid will be a vital component. Given the huge amount of data to be managed under smart-grid system with confidentiality, high value and cybersecurity as key concerns) CoE would need to develop an approach to manage the data while also ensuring data integrity and safety by bringing in other critical partners. The approach should include but not limited to investigating the relevance of blockchain technology (BCT) within smart grid platform. Blockchain-enabled transacting would ensure safe/secure real-time transacting. The digitalisation of the current municipal grid network would provide additional enhancement to the physical resources for customers to access the available services as well as for the municipal utility to improve on the management of the systems and the grid. The smart grid [provisioning of automation and sensors in the network coupled with communication over different channels, such as internet, GSM, Power Line Carrier-PLC adds value by ensuring seamless grid integration of all PV systems, monitoring and control, as well as real-time transacting for billing. It is likely to have huge initial costs, but the long-term benefits include increased efficiency in grid operations.

Financing is another feature of this model. The Development Bank of Southern Africa (DBSA), Industrial Development Corporation (IDC) and the African Development Bank (AfDB) are some of the possible favourable sources of funding for CoE as a sphere of government. CoE is thus better placed to source funding at affordable costs for RE projects. Currently, DBSA runs the Vumela Enterprise Development Fund, which is meant to support the implementation of municipal infrastructure projects. However, as alluded to by a DBSA participant, municipalities have not systematically taken advantage of such financing options.

An increase in the utilisation of such facilities, especially towards spearheading the adoption of distributed PV generation, puts the City at an advantage of succeeding in implementing the entire model. The African Development Bank has also been influential in funding renewable energy projects across the African continent at concessional funding and is being supported by other development partners as part of its initiative to power and light Africa. CoE could also engage the national government and design frameworks that allow CoE (as a municipality) to tap into such funding lines. African Development Bank has built internal capabilities to evaluate the economic viability of such projects and is thus well-positioned to assist with both technical and funding proposals. Currently, the African Development Bank has set up and capitalised the Sustainable Energy Fund for Africa (SEFA) with US$95 million and is supported by collaborating partners and governments from developed countries (Adesina, 2020).

6.2.7 Key Partners

The key partners identified include the partners found in the current business model as listed in the initial BMC (see page 29, Table 2.3). Each partner has a key role to play, and the new key partners would include SSEGs and IPPs. The SSEG component of the model involves the municipal utility addressing the supply side of the value chain by introducing a municipal driven rooftop program, funded (internally or through external financiers), managed and operated by CoE, as well as accepting surplus electricity generated by the customer. The financier are key partners that bring a key resource in the form of finance. They play a key role through mobilisation of funding and structuring financing modalities that de-risk identified projects. Typical key partners will include among others, financiers such as Development Bank of Southern Africa (DBSA), Industrial Development Corporation (IDC) and the African Development Bank (AfDB). Other key partners would thus include Eskom SOC, internet service providers, third-party vendors/retailers, OEMs, Service Providers/ESCos, NERSA, independent power producers, SSEGs and prosumers.

Based on a typical PPP, the ESCo option is preferred in this model for implementation due to inadequate resources under the prevailing municipal operations. This also creates a relationship between the private sector and the public sector, where each party benefits. The ESCo thus brings the technical expertise and conducts the audit, design and supply of equipment. In return, the municipal power utility benefits in achieving service delivery and protecting their revenue. Other equipment manufacturers (OEMs) are always relevant as they manufacture the physical equipment required to deliver the value proposition to the different customer segments. Regulatory approval by NERSA is very important for the new model to remain compliant with applicable rules and laws as they evolve.

6.2.8 Cost Structures

The cost structure remains largely the same with the additional transitional requirements for modernisation and digitalisation of the network or implementation of a smart grid. This comes at costs that are initially high and require innovative financing strategies, such as off-balance-sheet financing. The electricity purchase cost is likely to remain the largest cost, followed by operational and maintenance costs. The other cost would be the free electricity that the CoE supplies to indigents and other qualifying customers. This cost is currently partly funded through equitable share to a certain extent beyond which the municipality needs to cover in the form of top-up. Both TLs and NTLs, also count as components of the cost structure.

Appendices D and E show a breakdown of Eskom costs that were passed through to each customer category for period 2016/17 and 2017/18. These costs represent the LCOE for grid electricity but excludes the costs for CoE to deliver the electricity to its destination or final customers within its licensed area.

6.2.9 Revenue Streams

A reform of the current rate structure is required to correct what is currently outdated and obsolete. The current tariff structure is such that CoE recovers 82% of its CoS from sales of kWh (CoE, 2018). This poses a serious threat to revenue under the current transition. The revenue stream component of the proposed model requires the introduction of decoupling mechanism of sales from revenue. As appraised in Chapter 2 (Section 2.2), decoupling results in the revenue collection being less dependent on sales of kWh. As a result, the decline in sales need not negatively impact on the collected revenue primarily because the fixed costs of the power utility would be recovered primarily from a fixed charge, which can be equitably apportioned to the different customer groups. This would ensure that CoE can recover all the fixed costs associated with operations for the provisioning of electricity, including the maintenance of the infrastructure irrespective of the sales-volume. This is done through a tariff structure that includes fixed charges as highlighted in the tariff design methodology.

However, decoupling alone does not fully address the deficiencies of the current model. Appendices F and G show the total CoS for CoE for 2016/17 and 2017/18 financial years (R12.2 billion and R12.9 billion respectively). CoE had already introduced a fixed charge by 2016/17 financial year, which generated revenue of R234.1 million and R238.5 million for 2016/17 and 2017/18 financial years, respectively. Even though this revenue from fixed charges does not cover all CoE's fixed costs, it is a clear step towards the decoupling of revenue from sales-volumes.

Appendices D and E also show that Eskom has already introduced a fixed charge in efforts to decouple sales from revenue. However, the fixed charge is too low and is far from adequate towards recovering the fixed costs. The fixed costs for CoE are represented in the CoE operations column (Appendix F and G) and were R2.99 billion and R3.04 billion for period 2016/17 and 2017/18 respectively. Analysis of the data shows that CoE could hypothetically increase the fixed charge annually until it reaches 100% of the CoE operations. However, while increasing the fixed cost charges, CoE would also need to continuously enhance cross-subsidisation to cover the indigent residents in the municipality who will increasingly find it impossible to meet the cost of service. Such decoupling of sales from revenue would also require a gradual implementation process to avoid price shocks that can be detrimental to the economy.

As noted earlier (see section 2.2.3) the CoS method fails to address inefficiencies, and as a result, operational efficiencies become a focal point towards improving on utility revenue. In addressing inefficiencies, the study has identified key performance areas such as NTLs, EEDSM, LCOE and digitalisation of the network. Wheeling was also identified as a relevant opportunity in the new model as it allows for an IPP located anywhere to be connected to the consumer via the municipal grid and any other interconnecting grids in order to provide access from the generator to the customer. Such an arrangement requires the IPP to pay the municipal power utility a wheeling charge. This wheeling charge requires approval from NERSA and would then constitute an additional revenue stream for the utility. Such additional revenue streams for the utility could be directed towards the funding of the 100 kWh units for the qualifying indigent customers.

6.2.10 Diagrammatic representation of the responsive business model

Figure 6.2 shows a summary of the proposed innovative business model explained in prior sections and how the key stakeholders are interlinked. At the centre of this model is the municipal revenue pool.

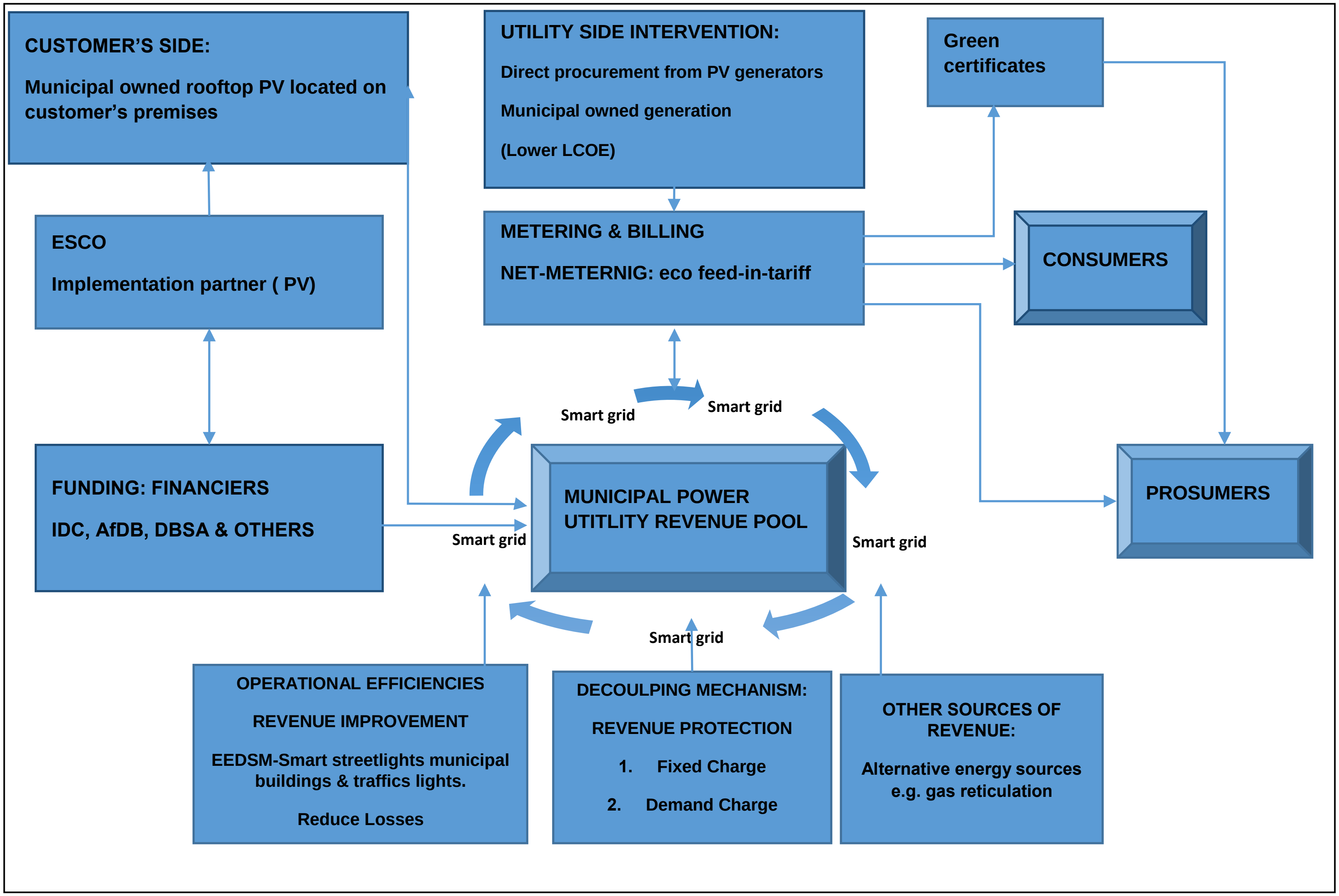

Figure 6.2: Responsive business model framework for municipal utilities

7 OVERALL FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

7.1 Introduction

This chapter presents a consolidation of the findings, overall conclusions and recommendations of the research study as guided by the research questions and objectives. Although it was beyond the scope of the study to provide the actual measures to be implemented by CoE and the generality of municipalities to adapt to the current transition in the electricity market, the insights provided herein are likely to be of interest to majority of policymakers across South Africa. This chapter concludes by providing recommendations on further areas of research in order to support the country's objectives of increasing renewable energy in the energy mix, curtail power shortages and improving access to energy as measured by the country's electrification rate as well as development of additional business models suitable for the South African municipal power utilities.

7.2 Consolidation of sub-finding findings

CoE's average annual electricity purchases from Eskom were 10,722,439,168 kWh for period 2008 to 2018, the electricity purchases peaked in 2008/2009 to 10,974,168,017 kWh. Although the annual purchases from Eskom have been relatively stable with minimum variation, the total annual average purchases show of 0.37%. The study finds that revenue has also been declining at the same time, as would have been expected.

The annual average electricity sales for CoE for the same period 2008 to 2018 was calculated to be at 0.97%, showing that the uptake of electricity has not significantly increased, however the data shows that non-technical losses began to increase from 2013/14 and the situation has been worsening. The non-technical losses of COE for 2018 shows losses amounting to 5.79% or R533,183,567. This performance is better when compared with the 9.36% (R970,589,000) and 14.82% (R1,537,624,000) for City of Johannesburg and City of Tshwane respectively. Non-technical losses have direct impact on revenue collected by the city, and an improvement in this figures would result in increased revenue. Figure 4.8 shows the declining revenue performance of CoE for the period 2008 to 2018, and this decline can be attributed to various causes such as increased adoption of distributed PV and increasing non-technical losses among others. Distributed PV trends in COE are showing an exponential increase from a recorded 0.36MW installed capacity in 2013 to 28MW installed in 2018. This finding does not include unauthorised or unregistered distributed PV system.

The increasing distributed PV systems will always have an impact on the revenue collected by CoE due to the fact that the prevailing business model for municipal power utilities does not respond to the current transition in the electricity sector as it emphasizes procurement of electricity from mainly a sole supplier being Eskom for resale to consumers based on the designed tariff structures. These tariff structures used by municipal power utilities lean more towards collection of sales revenues from consumption charges (in kWh). For example, the study finds that the current tariff design for CoE allows it to collect 82% of its electricity revenue from the sales of electricity units and this leaves some fixed costs being borne by the municipal authority. This business model presents challenges during the current transition in the electricity sector, where the diffusion of distributed PV generation penetration continues to grow as customers respond to rising tariffs for grid electricity in South Africa. This has led to dwindling of sales (consumption) without a proportional drop in fixed costs, and these will continue to be carried by municipal authorities.

The responsive business model proposed in chapter 6 is aimed at addressing revenue gap created on municipal revenue by the increasing distributed PV on municipal revenue. The municipal customer base was used to determine the revenue gap created by this increasing distributed PV generation. CoE has 427,000 customers of whom 102,000 are indigents (these are customers who depend on government grants for their livelihood). This leaves 325,000 active customers who are likely to install distributed PV systems. This number includes 8,500 large customers who are likely to install PV systems with a calculated capacity of 1,376 MW (based on actual data collected) which represents 55% of the total installed capacity in CoE. These installations could have a maximum possible net effect of reducing the municipal revenue by 19% (R2.2billion) annually. The remaining 317,000 customers have a potential of a possible 951MW based on a 3kVA system for each customer (Korsten et al., 2019:36). The energy yield for 951MW is calculated to be 1,181,732,320 kWh annually, which represents 11.13% or R1.536 billion of possible revenue loss for CoE, this brings the total possible revenue gap under distributed PV to 30.13% or R3.736 billion annually (based on average electricity cost of R1.30/kWh)

This revenue gap poses a threat to municipal revenue as customers continue to either defect from the grid or reduce their reliance on the grid, as the prices of PV systems continue to drop. The study further shows that PV LCOE has already surpassed the grid parity threshold and continues to fall below this threshold making it attractive for consumers who afford to install their own small-scale generating units for their consumption. This creates a need for municipal power utilities to re-assess their prevailing business models with the aim of formulating a responsive business models that recognize this transition. In the absence of any action from power utilities, their financial sustainability is threatened which may ultimately lead to total collapse of the local authorities.

In response to this transition, a business model such as the one detailed in chapter 6 aims to be responsive to this transition. The responsive business model is based on the several significant parameters that are relevant to increasing municipal revenue without hindering the increasing distributed PV generation. These significant parameters are LCOE, operational efficiency and tariffs. In addition to these parameters, the study highlights the importance of the management of data flow in the entire value chain. The procurement of electricity generated from energy sources with a LCOE provides financial benefits the power utilities resulting in increased revenue. Operational efficiencies as described above present further opportunities for the power utility to lower their operational costs thereby improving revenue. This can be achieved by implementing mechanisms for minimising electricity losses. Furthermore, implementation of energy efficiency and demand side management play a critical role in enhancing the financial and technical performance of a utility. Tariffs as a mechanism used by municipal power utilities to collect revenue, are currently inefficiently structured to respond to this transition. The current tariff structure for municipal power utilities is such that electricity sales constitute the largest component of the utilities' revenue stream. This poses further threats that could lead to the collapse all other municipal services should municipalities fail to change their business models and include the components indicated in the proposed responsive model. A suggested solution to the challenges posed by this is the decoupling of municipal revenue from volumetric sales of electricity units.

The inactiveness of municipal power utilities and the continuation of their business-as-usual approach during the current transition in the energy sector pose significant risks to all municipalities that distribute electricity. The biggest risk facing the utilities is the loss of revenue due to increased distributed PV. Under the current municipal business model, this loss of revenue can lead to a death spiral and result in unsustainable electricity operations.

In developing the business model in chapter 6. The BMC tool was identified as an appropriate tool for mapping the existing municipal power utility's business model first and thereafter apply it to develop and propose a new business model, taking into consideration the current transition in the electricity sector of South Africa.

This research seeks to ignite robust debate on the need to restructure the current business models of municipal power utilities. The time has never been more ideal than now when the country is facing rolling power cuts as Eskom struggles to maintain supplies. The findings of this study identify critical players while also providing the necessary pointers on how the new electricity business models can be configured at the municipal level. Further research is now required to explore (in detail) how the various institutional actors can be brought together to develop the necessary policy framework and operational plans to encourage such business model restructuring. Further research work will include assessing the costs of integrating distributed generation into the grid and the adequacy of current infrastructure. This can all be achieved by putting together a comprehensive framework that brings all relevant stakeholders to work together.

7.3 Overall conclusions and recommendations

As discussed in chapter 1, South African municipal power utilities are faced with a challenge of protecting their electricity revenue under the increasing distributed PV generation. Diverse studies now concur that the historical business models for all municipal utilities in South Africa are no longer viable under the current and near-future trends. The reliance on volumetric sales of electricity units for deriving revenue would inevitably pose a critical death spiral risk for Eskom and the municipal power utilities simultaneously.

In addressing the overall research question, the proposed business model for implementation by CoE would encourage participation of municipal customers, both residential and industrial. The prevailing business model is unsustainable under the current electricity sector transition. The conceptualised responsive business model in chapter 6 is aimed at mitigating these challenges.

The success of the proposed responsive model would be driven by the ability of stakeholders in the industry to coordinate and come up with a comprehensive implementation framework as well supporting regulatory frameworks and sustained political will (Tyabashe, 2018). The growth of distributed PV generation and the feeding of surplus electricity to the grid relies on extensive technological developments built around information technology and communication tools, such as internet of things (IoT), block-chain and others. It is critical for the government to promulgate comprehensive legislation that seeks to protect electricity consumers from the risk of information theft through cyberattack of grid systems, such that the initially noble aspiration poses disastrous consequences for the municipalities and other stakeholders.

Financiers would also play a crucial role through the mobilisation of funding and structuring financing modalities that eliminate or reduce risks inherent in the identified projects. Financial institutions, such as AfDB and the International Finance Corporation (IFC), have built capabilities in developing renewable energy sources supported by an extensive network of development-minded investors. It is critical that local financial institutions partner with such organisations to provide structured risk analysis to ensure bankability of RE projects at diverse scales. The South African Government should also provide financial incentives to pursue a two-pronged strategy aimed at stabilising Eskom in the short term and developing alternative energy sources at a large scale. The government could take a cue from Kenyan authorities, which have led from the front in the development of renewable power sources ably supported by African Development Bank and other international development partners, such that the country increased its nationwide electrification rate from 29% in 2013/14 to 73% in 2017/18 financial year (IEA,2019).

It is recommended that municipal power utilities should start investing resources in developing and testing new business models that suit their environments, such as the one proposed in this study in order to address the identified risks. As the first step to implementation, there is a need to ensure that prioritised technological interventions are available and at the right cost. Regulatory realignment would also be critical for compliance with the evolving policies and frameworks for the sector. It is further recommended that municipalities and the South African Government should encourage those who manufacture the technology (OEMs) to partner with other investors on build, operate and transfer models. This ensures that the country benefits from increased access to the technology, as well as the imparting of relevant technical skills to its residents. It is, therefore, recommended that CoE should therefore explore the overall approach/strategy as well as funding mechanisms for implementing the smart-grid initiative in detail. Proactive participation in smart grid pilot programme under the South African National Energy Development Institute-SANEDI could assist CoE in the initial explorations and prototyping/piloting.

It is further recommended that municipal power utilities should be operated as energy utilities rather than electricity utilities. As a result, they should be focused on providing energy solutions rather than merely reselling electricity. It is, therefore, urgent that the CoE explores its participation in alternative energy markets. The proposed model introduces “the wheeling concept”, which allows for a non-municipal generator to transport electricity to a customer through the municipal-owned grid subject to payment of agreed tariff costs (called wheeling charges).

There is also a need to research further on how the regulatory environment can be improved in order to accommodate current industry dynamics without compromising on standards. Generally, NERSA has lagged behind the dynamic changes in the electricity market, thereby ending up as a bottleneck to responsive developments for the transition of the sector. NERSA could understudy how other countries are regulating/managing distributed generation for successful integration into the grid. It would also require that stakeholders formulate clear roadmap to guide the development of the regulatory and operational frameworks. NERSA, as a regulatory authority, is also required to move away from the current benchmarking regulatory method and thus facilitate the adaptation to the ongoing energy transition for the sector as a whole. To plug the revenue gap brought about by changes in the energy sector, municipalities need to innovate on their business models, and one option is to consider electricity wheeling rather than the sale of electricity as a commodity. This would entail opening the distribution network to other generators to directly supply electricity to dedicated customers.

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9 OVERALL LIST OF APPENDICES

This section presents the following list of appendices:

Appendix A: Notified maximum demand per town (Source: CoE eVenus system)

POINT OF SUPPLY	NOTIFIED MAX DEMAND (MW)
Alberton Albertsdal	5
Alberton Alrode	113
Alberton Eiger	113
Benoni Benburg 132KV Substation Benoni 132	75
Benoni 132KV Substation	75
Benoni 44 Substation	85
Boksburg Town	85
Boksburg North	175
Boksburg Mapleton	165
Boksburg Reiger Park	15
Boksburg Finaalspan	28
Brakpan Town	105
Brakpan NORTH	6
Brakpan Ergo Central	20
Germiston Munic	100
Germiston South	130
Germiston North	103
Germiston Union	60
Germiston Rietcons	50
Elsburg Municipality	16

POINT OF SUPPLY	NOTIFIED MAX DEMAND (MW)
Germiston Bedfordview	85
Nigel Bulk	48
Nigel Dunnotar	6
Springs - Sharon Park	3,5
Springs Bulk	68.3
Springs Munic	67
Springs KwaThema	36
Springs Modder East	8000
Springs Selcourt	39.1
Springs Welgedacht 6kv	4
Edenvale Main	42
Edenvale Industries	33
Edenvale Horwood	14
Kempton Munic	165
Kempton Croydon	45
Kempton Avion	11,5
Kempton Klipfontein	700
Kempton Esselen	40
Kempton 132KV	60
Clayville Ext 13 - Cullip 6,6	5
Clayville Ext 13 - Cullip 11	5

POINT OF SUPPLY	NOTIFIED MAX DEMAND (MW)
Clayville Ext. 4 - Clayville 6,6	16
Clayville Ext. 4 - Clayville 11	10
Clayglass	30
Tembisa	92
Kempton Ester Park	20
Jack Shaft 11kv	3,5
Tsakane Bulk	8
ijvouiyu South mp1 11kv	18
Vosloorus Ext 28	70
Marievale GM MP1 6,6KV	1
Nestle Purina	4
Consol Glass Clayville MP1 & MP2	23
EMM Hippo Quarries	30
Palm Ridge Substation MP1 & 2	250
New Dunnotto Account	60
Total NMD	**2,525**

Appendix B: Cumulative SSEG penetration in CoE (Source: Adapted from CoE eVenus system)

Year	Installed Capacity (MW)
2012/13	0.35
2013/14	1.28
2014/15	4.17
2015/16	12.26
2016/17	19.7
2017/18	28.4

Appendix C: Breakdown of Eskom costs to CoE per customer category - 2016/17 (Source: CoE eVenus system)

Description	Energy ZAR	Capacity ZAR	Demand ZAR	Excess ZAR	Fixed ZAR	TOTAL ZAR	Capacity ZAR
Tar A Bus	88,236,684	7,551,443	4,627,061	-	107,898	100,523,085	27,109,056
Tar A Res (IBT)	788,166,304	25,925,150	45,768,400	-	492,886	860,352,740	252,466,048
Tar B Res	1,367,647,552	88,391,776	63,635,552	-	730,791	1,520,405,671	362,921,152
Tar B Resellers 400v	221,562,848	11,703,540	10,414,393	-	105,677	243,786,458	63,324,324
Tar B Resellers > 400v	18,984,888	919,845	1,089,389	-	937	20,995,059	1,066,925
Tar B Resellers > 400v	43,511,046	1,934,501	1,752,383	83,771	2,186	47,283,887	1,522,612
Tar B Bus (Mixed)	330,812,784	27,549,216	16,637,834	-	704,820	375,704,654	96,804,656
Tar C 400 V	434,616,592	67,126,760	38,167,724	-	41,995	539,953,071	177,644,320
Tar C 400 Sub	13,403,970	1,868,887	1,077,828	-	547	16,351,231	5,224,343
Tar C<=11kV	175,157,472	24,817,556	16,115,726	-	9,020	216,099,774	51,063,828
Tar C<=11kV	400,210,528	51,985,568	25,792,532	1,067,601	21,046	479,077,274	70,993,744

Tar C<=11kV(Off -Peak)	3,446,770	724,407	307,548	13,005	471	4,492,201	841,612
Tar D 400 V Sub	1,906,591	428,838	278,664	-	22	2,614,114	979,140
Tar D<=11kV	194,819,144	19,172,892	12,962,749	-	758	226,955,543	43,127,796
Tar D<=11kV	1,715,393,344	154,910,032	79,982,008	3,174,021	6,821	1,953,466,225	219,660,704
Tar D>11kV	730,770,016	60,195,520	48,537,088	1,314,678	663	840,817,965	1,977,074
Tar E 400V	226,774,656	34,794,252	19,775,918	-	20,221	281,365,047	93,489,336
Tar E 400V Sub	22,000,806	3,214,752	1,874,849	-	1,251	27,091,657	8,882,215
Tar E<=11kV	145,957,260	18,194,324	11,981,386	-	5,719	176,138,689	39,103,896
Tar E<=11kV	571,354,640	65,326,548	32,864,310	1,314,103	22,876	670,882,477	91,711,976
Tar E>11kV	3,128,717	355,770	392,630	9,333	68	3,886,518	501,447
Tar F Lights	120,614,472	-	10,846,931	-	128,576	131,589,979	51,891,296
Tar F Traffic	1,482,254	86,624	50,734	-	1,299	1,620,911	310,332

Tar I CP<=66kV	10,551,069	1,612,667	581,298	7,095	86	12,752,216	876,337
Tar D3 A***l	99,618,446	6,296,522	2,136,793	148,122	32	108,199,915	-
TarD2 B***	22,869,762	1,794,623	2,095,937	15,767	32	26,776,121	-
Tar D2 C***	30,396,039	2,450,247	1,981,200	-	32	34,827,518	-
Tar D2D***	201,463,328	13,198,581	15,391,567	352,754	32	230,406,263	-
Tar D2 D***	12,676,423	876,823	1,018,953	22,509	32	14,594,740	-
Total	**7,997,534,405**	**693,407,664**	**468,139,385**	**7,522,759**	**2,406,794**	**9,169,011,003**	**1,663,494,169**

*** name of customers withheld

Appendix D: Breakdown of Eskom costs per customer category, 2017/18 (Source: CoE eVenus system)

Description	Energy ZAR	Capacity ZAR	Demand ZAR	Excess ZAR	Fixed ZAR	TOTAL ZAR	Capacity ZAR
Tar A Bus	88,536,120	7,551,443	4,642,515	-	108,727	100,838,805	28,816,320
Tar A Res (IBT)	790,832,224	26,119,712	45,921,220	-	511,569	863,384,725	268,364,384
Tar B Res	1,372,288,640	89,055,128	63,848,024	-	731,071	1,525,922,863	385,765,984
Tar Resellers 400V	222,316,312	11,791,355	10,449,181	-	105,109	244,661,957	67,311,360
Tar B Rellers>400V	19,043,345	928,128	1,092,649	-	1,011	21,065,132	1,137,619
Tar B Resellers>400V	43,678,796	1,944,579	1,759,455	84,040	2,360	47,469,230	1,623,426
Tar B Bus (Mixed)	331,935,632	27,755,930	16,693,397	-	693,671	377,078,630	102,900,320
Tar C 400 V	436,091,952	67,630,648	38,295,144	-	42,177	542,059,921	188,839,152
Tar C400 V Sub	13,449,429	1,882,917	1,081,431	-	529	16,414,304	555,595
Tar C <=11kV	175,696,880	25,041,264	16,163,944	-	8,915	216,911,003	54,232,744

Tar C<=11kV	401,743,600	52,255,912	25,896,504	1,071,031	20,801	480,987,848	75,689,256
Tar C <= 11kV (Off-Peak)	3,460,033	728,176	308,789	13,047	463	4,510,507	897,276
Tar D 400V Sub	1,913,113	432,057	279,594	-	22	2,624,786	1,041,259
Tar D<=11kV	195,418,512	19,345,718	13,001,534	-	780	227,766,544	45,803,372
Tar D<=11kV	1,721,874,944	155,715,616	80,304,240	3,184,220	7,021	1,961,086,040	234,189,024
Tar D>=11kV	733,009,920	60,367,932	48,681,640	1,318,903	694	843,379,089	2,107,885
Tar E 400 V	227,542,056	35,055,396	19,841,922	-	21,684	282,461,058	99,380,664
Tar E 400 V Sub	22,074,340	3,238,897	1,881,094	-	1,609	27,195,940	9,445,402
Tar E<=11kV	146,406,448	18,358,326	12,017,234	-	6,058	176,788,066	41,530,392
Tar E<=11kV	573,520,432	65,666,180	32,996,704	1,318,326	24,233	673,525,875	97,777,800
Tar E>11kV	3,138,319	356,789	393,799	9,363	66	3,898,336	534,602

Tar F lights	121,013,948	-	10,883,127	-	130,894	132,027,969	55,159,800
Tar F Traffic	1,487,237	87,274	50,903	-	1,322	1,626,736	329,845
Tar I CP<=66kV	10,589,808	1,620,969	583,605	7,118	132	12,801,631	934,362
Tar D3 ***	99,928,076	6,317,150	2,143,619	148,598	33	108,537,476	-
Tar D2 D2 ***	23,122,910	1,855,157	2,117,493	15,818	33	27,111,410	-
Tar J ***	30,489,109	2,706,454	1,987,105	-	33	35,182,701	-
Tar J ***	203,570,672	13,643,780	15,549,909	353,888	33	233,118,282	-
Tar D2***	12,810,184	906,399	1,029,455	22,581	33	14,768,652	-
Total	**8,026,982,991**	**698,359,286**	**469,895,230**	**7,546,933**	**2,421,083**	**9,205,205,516**	**1,764,367,843**

*** name of customers withheld

Appendix E: Total costs of supply for CoE for 2016/17 (Source: CoE eVenus system)

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	**UNBUNDLED ESKOM COSTS TO BE PASSED THROUGH TOTAL ZAR**	**TOTAL ZAR**	**ZAR**	**FIXED ZAR**	**LOW ENERGY DEMAND ZAR**
Tar A Bus	100,838,805	49,074,002	149,912,807	4,101,966	124,237,504
Tar A Res (IBT)	863,384,725	726,619,712	1,590,004,437	-	495,671,200
Tar B Res	1,525,922,863	838,082,336	2,364,005,199	66,803,320	1,688,272,128
Tar B Resellers 400 V	244,661,957	133,629,040	378,290,997	16,439,382	256,225,616
Tar B Resellers 400 V	21,065,132	1,834,826	22,899,958	1,318,248	22,638,458
Tar B Resellers 400 V	47,469,230	3,250,243	50,719,473	3,075,912	52,823,064
Tar B Bus (Mixed)	377,078,630	258,819,200	635,897,830	13,719,744	349,678,432
Tar C 400 V	542,059,921	201,550,587	743,610,508	40,810,000	355,884,416

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	UNBUNDLED ESKOM COSTS TO BE PASSED THROUGH TOTAL ZAR	TOTAL ZAR	ZAR	FIXED ZAR	LOW ENERGY DEMAND ZAR
Tar C 400 V Sub	16,414,304	5,714,986	22,129,290	511,724	11,078,440
Tar C<=11kV	216,911,003	56,919,480	273,830,484	8,161,554	144,304,528
Tar C<=11kV	480,987,848	81,958,305	562,946,153	19,043,624	336,710,528
Tar C<=11kV(Off-Peak)	4,510,507	1,036,743	5,547,250	423,662	2,771,264
Tar D 400 V Sub	2,624,786	1,047,901	3,672,686	29,840	1,350,901
Tar D<=11kV	227,766,544	46,038,474	273,805,018	704,219	155,285,008
Tar D<=11kV	1,961,086,040	236,304,940	2,197,390,980	6,337,973	1,397,565,056
Tar D>=11kV	843,379,089	2,317,086	845,696,174	941,664	569,758,080
Tar E 400 V	282,461,058	105,915,697	388,376,755	18,815,576	190,340,544

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	**UNBUNDLED ESKOM COSTS TO BE PASSED THROUGH TOTAL ZAR**	**TOTAL ZAR**	**ZAR**	**FIXED ZAR**	**LOW ENERGY DEMAND ZAR**
Tar E 400 V Sub	27,195,940	9,930,216	37,126,156	1,395,871	22,205,032
Tar E<=11kV	176,788,066	43,263,465	220,051,531	5,564,799	125,672,560
Tar E<=11kV	673,525,875	104,710,092	778,235,966	22,259,196	502,690,240
Tar E>11kV	3,898,336	554,525	4,452,861	60,725	2,408,076
Tar F Lights	132,027,969	84,372,278	216,400,247	-	173,843,840
Tar F Traffic	1,626,736	624,920	2,251,657	-	1,433,718
Tar I CP <=66 kV	12,801,631	974,210	13,775,841	441,084	8,965,035
Tar D3 ***	108,537,476	9,962	108,547,438	44,841	89,768,488
Tar D2 ***	27,111,410	9,962	27,121,372	29,840	20,090,300

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	**UNBUNDLED ESKOM COSTS TO BE PASSED THROUGH TOTAL ZAR**	**TOTAL ZAR**	**ZAR**	**FIXED ZAR**	**LOW ENERGY DEMAND ZAR**
Tar J ***	35,182,701	9,962	35,192,663	1,505,880	23,409,492
Tar J***	233,118,282	9,962	233,128,244	1,505,880	154,146,592
Tar D2 ***	14,768,652	9,962	14,778,613	29,840	11,979,090
Total	9,205,205,515	2,994,593,073	12,199,798,588	234,076,363	7,291,207,630

Appendix F: Total costs of supply for CoE for 2017/18 (B) (Source: CoE eVenus system)

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	Unbundled Eskom costs to be passed through TOTAL ZAR	TOTAL ZAR	ZAR	Fixed ZAR	Low Energy Demand ZAR
Tar A Bus	108,220,201	53,229,538	161,449,739	4,101,966	124,237,500
Tar A Res (IBT)	926,584,494	631,515,520	1,558,100,014	-	495,671,200
Tar B Res	1,637,620,465	897,928,256	2,535,548,721	66,803,319	1,688,272,120
Tar B Resellers 400 V	262,571,217	142,973,208	405,544,425	16,439,382	256,225,626
Tar B Resellers> 400 V	22,607,098	1,949,076	24,556,175	1,318,248	22,638,457
Tar B Resellers> 400 V	50,943,978	3,476,916	54,420,893	3,075,912	52,823,063
Tar B Bus (Mixed)	404,680,794	285,163,088	689,843,882	13,719,744	349,678,422
Tar C 400 V	581,738,712	210,689,348	792,428,060	40,810,002	355,884,406

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	**Unbundled Eskom costs to be passed through TOTAL ZAR**	**TOTAL ZAR**	**ZAR**	**Fixed ZAR**	**Low Energy Demand ZAR**
Tar C 400 V Sub	17,615,832	5,955,004	23,570,836	511,724	11,078,440
Tar C<=11kV	232,788,873	59,428,602	292,217,476	8,161,554	144,304,537
Tar C<=11kV	516,196,160	85,714,251	601,910,410	19,043,625	336,710,569
Tar C<=11kV(Off-Peak)	4,840,676	1,089,871	5,930,547	423,662	2,771,264
Tar D 400 V Sub	2,816,920	1,089,807	3,906,727	29,840	1,350,901
Tar D<=11kV	244,439,050	47,889,278	292,328,329	704,219	155,285,015
Tar D<=11kV	2,104,637,431	245,644,546	2,350,281,977	6,337,973	1,397,565,083
Tar D>=11kV	905,114,423	2,426,262	907,540,685	941,664	569,758,048
Tar E 400 V	303,137,209	110,704,816	413,842,025	18,815,576	190,340,546

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	Unbundled Eskom costs to be passed through TOTAL ZAR	TOTAL ZAR	ZAR	Fixed ZAR	Low Energy Demand ZAR
Tar E 400 V Sub	29,186,682	10,366,515	39,553,197	1,395,871	22,205,033
Tar E<=11kV	189,728,953	45,145,102	234,874,055	5,564,799	125,672,560
Tar E<=11kV	722,827,950	109,420,041	832,247,991	22,259,197	502,690,242
Tar E>11kV	4,183,694	577,837	4,761,531	60,725	2,408,076
Tar F Lights	141,692,415	90,736,774	32,429,189	-	173,843,835
Tar F Traffic	1,745,814	680,235	2,426,049	-	1,433,718
Tar I CP <=66 kV	13,738,710	1,015,628	14,754,338	441,084	8,965,035
Tar J ***	116,482,420	11,277	116,493,698	1,505,880	78,570,651
Tar J ***	29,095,966	11,277	29,107,243	1,505,880	16,477,865

	ESKOM	CoE OPERATIONS	TOTAL SUPPLY COST		CoE REVENUE FROM TARIFFS
DESCRIPTION	**Unbundled Eskom costs to be passed through TOTAL ZAR**	**TOTAL ZAR**	**ZAR**	**Fixed ZAR**	**Low Energy Demand ZAR**
Tar J ***	37,758,072	11,277	37,769,350	1,505,880	23,409,492
Tar J ***	250,182,526	11,277	250,193,803	1,505,880	154,146,590
Tar J ***	15,849,717	11,277	15,860,994	1,505,880	9,730,043
Total	**9,879,026,452**	**3,044,865,905**	**12,923,892,357**	**238,489,485**	**7,274,148,378**

Appendix G: Electricity sales by calendar years (Source: CoE eVenus system)

Period	kWh	Change
Jan - Dec 2007	11,058,980,441	
Jan - Dec 2008	10,933,526,017	-1.13%
Jan - Dec 2009	10,754,027,663	-1.64%
Jan - Dec 2010	10,799,736,630	0.43%
Jan - Dec 2011	10,887,124,231	0.81%
Jan - Dec 2012	10,810,969,437	-0.70%
Jan - Dec 2013	10,725,291,900	-0.79%
Jan - Dec 2014	10,547,885,924	-1.65%
Jan - Dec 2015	10,483,275,363	-0.61%
Jan - Dec 2016	10,543,768,792	0.58%
Jan - Dec 2017	10,609,325,677	0.62%
Jan - Dec 2018	7,196,758,378	-32.17%

Appendix H: Annual CoE Electricity Sales (Source: eVenus system)

Year	Annual sales (kWh)	Annual Change (%)
2008/09	9,769,204,368.73	
2009/10	9,183,424,358.15	6.0%
2010/11	9,308,242,921.59	1.4%
2011/12	9,183,424,358.15	-1.3%
2012/13	9,719,061,523.86	5.8%
2013/14	9,183,424,358.15	-5.5%
2014/15	9,474,494,696.42	3.2%
2015/16	9,183,424,358.15	-3.1%
2016/17	9,309,093,466.46	1.4%
2017/18	9,379,317,010.54	0.8%
Annual Average	9,369,311,142.02	0.97%

Appendix I: Eskom bulk purchases versus CoE sales (Source: CoE eVenus system)

Tariff Group	Eskom Bulk Purchase (kWh)	CoE Sales to Customer(kWh)	% Loss
Tar A Bus	110,716,790	94,615,045	14.5%
Tar A Res (IBT)	1,067,784,192	920,783,774	13.8%
Tar B Res	1,749,995,264	1,501,197,274	14.2%
Tar B Resellers 400 V	281,299,160	240,930,550	14.4%
Tar B Resellers > 400 V	24,063,892	21,800,243	9.4%
Tar Resellers > 400 V	55,500,996	50,867,230	8.3%
Tar B Bus (Mixed)	415,542,176	355,285,511	14.5%
Tar C 400 V	542,189,984	463,504,372	14.5%
Tar C 400 V Sub	17,100,282	15,011,482	12.2%
Tar C<=11kV	220,210,596	194,877,544	11.5%
Tar C<=11kV	506,512,528	454,714,248	10.2%
Tar C<=11kV (Off-Peak)	4,303,958	3,858,450	10.4%
Tar D 400 V Sub	2,095,964	1,802,859	14.0%
Tar D<=11kV	261,354,616	232,077,790	11.2%
Tar D<=11kV	2,317,671,232	2,088,700,032	9.9%
Tar D>11kV	1,011,890,800	936,054,119	7.5%
Tar E 400 V	290,774,480	248,545,825	14.5%

Tariff Group	Eskom Bulk Purchase (kWh)	CoE Sales to Customer(kWh)	% Loss
Tar E 400 V Sub	29,848,443	26,283,988	11.9%
Tar E <=11kV	191,873,732	170,106,748	11.3%
Tar E<=11kV	756,451,024	680,426,991	10.1%
Tar E>11kV	4,031,560	3,636,183	9.8%
Tar F Lights	200,714,304	175,499,505	12.6%
Tar F Traffic	2,054,853	1,772,722	13.7%
Tar I CP<=66kV	15,107,888	13,918,050	7.9%
Tar J ***	145,065,984	145,065,981	0.0%
Tar J ***	29,911,058	29,911,058	0.0%
Tar J ***	43,185,057	43,185,056	0.0%
Tar J ***	285,499,088	285,499,087	0.0%
Tar J ***	17,715,898	17,715,898	0.0%
Total	**10,600,465,799**	**9,417,647,615**	

Appendix J: Breakdown of municipal street lighting infrastructure

Area	70 W Streetlights Installed	90 W streetlights installed	100 W streetlights installed	125W streetlights installed	135 W streetlights installed	150 W streetlights installed	250W streetlights installed	400W streetlights installed	400W streetlights installed	Total per town
Benoni	14431		4798			2414	3803	3133	291	28811
Alberton	9750						3250		200	13200
Boksburg	2650			23500			2920	60	700	29830
Brakpan	2000	23	20	989	105		2407	1644	390	7578
Germiston	10000			15000		5000	8000	2000	300	40300
Kempton Park	7500		800	7500		400	2200	700	3	19103
Springs & Nigel	8567			5474			1132	1702	293	17168
Tembisa	388		515	1876					242	3021
Edenvale	650			15000		120	1600	445		17815
Total	**55936**		**6073**	**69339**		**7934**	**25312**	**9684**	**2419**	**176697**

Appendix K: Interview transcript with SALGA official

Participant Interview Guide: March (SEEC) Research

Please note: -

- Questions below are intended to guide the interview and discussion with the participant
- Supplementary related questions may be included during the discussion; these will be documented and made available on request.
- Added questions will comply with the University's ethics guide

Questions

Information on business models (SALGA)-official as participant)

1. What is the role of SALGA in the energy industry?

SALGA is currently playing a pivotal role in the industry advocating for the transition of the current business models for electricity and energy in the municipal space and also carries a lobbying role on the policy reforms for the industry in turning around the ailing municipal electricity business; since the current model is threatened by the technology disruptions, SALGA is responsible for representing the local government positions at policy and regulation platforms. This is done by also participating in all IGR platforms that seek to address the systemic and structural challenges within the Electricity Distribution Industry in as far as municipalities and Eskom are concerned.

2. Do you think South Africa is on the right regulatory trajectory in terms of an embedded generation especially PV when compared with peers and the rest of the world and what is our state of readiness for this transition?

Currently, there is regulatory lag because the industry is and has been developing on its own in the absence of regulation. The South African regulatory environment still very much limits the development of this industry and constraining PV development to centralised projects that are implemented through government and Eskom. In the distribution space there are several *limitations for this industry to thrive, one example being the limitation of MW on the embedded generation, which is even done at the recent IRP2018, where 200 MW per year is allocated until 2030 but the evidence of the current developments far exceeds the 200 MW per year. The minister seems to still have too many powers over the development of the embedded generation because what is in the IRP must be determined by the Minister through new generation regulations.*

3. What is the view of SALGA on distributed PV generation and its impact on municipal revenue?

For some time, there has been a misconception about distributed generation in municipalities, but SALGA's understanding is that while there is a threat in revenues but this change also presents opportunities for municipalities to review their business models on electricity and even identify other revenue streams over and above selling kWhs.

4. Should municipalities encourage distributed PV generation?

They should encourage it but first things first, prepare themselves to manage and administer the development thereof but ensuring that there are tariffs that will enable them to recover their network charges still so as to gain revenue even when the customers are not consuming their grid power, ensure there are technical processes in place to look at safety and power quality matters etc.

5. What trajectory is this impact expected to take and corresponding effects on municipal revenue?

If municipalities reviewed their business models and processes to respond to the development of distributed generation, the impact could be positive rather than the perceived narrative of negative impact.

6. What is the suggestion to municipal approach to distributed PV?

The approach and guiding principles that we normally give municipalities are:

- **<u>Avoid informal connections (SAFETY!!!!!!!</u>** <u>And financial implications</u>**<u>)</u>**
  - Sufficient incentive (export tariff)
  - Low administrative overheads and processing times
- **<u>Encourage SSEG uptake through:</u>**
  - Security of investments (guaranteed tariff or concept)
  - Low overhead costs for additional equipment, such as meters etc.
- **<u>Limit impact on municipal revenue:</u>**
  - Tariffs that cover the cost of grid usage
  - Export tariff that is sufficiently low
- **<u>Decrease peak consumption</u>**

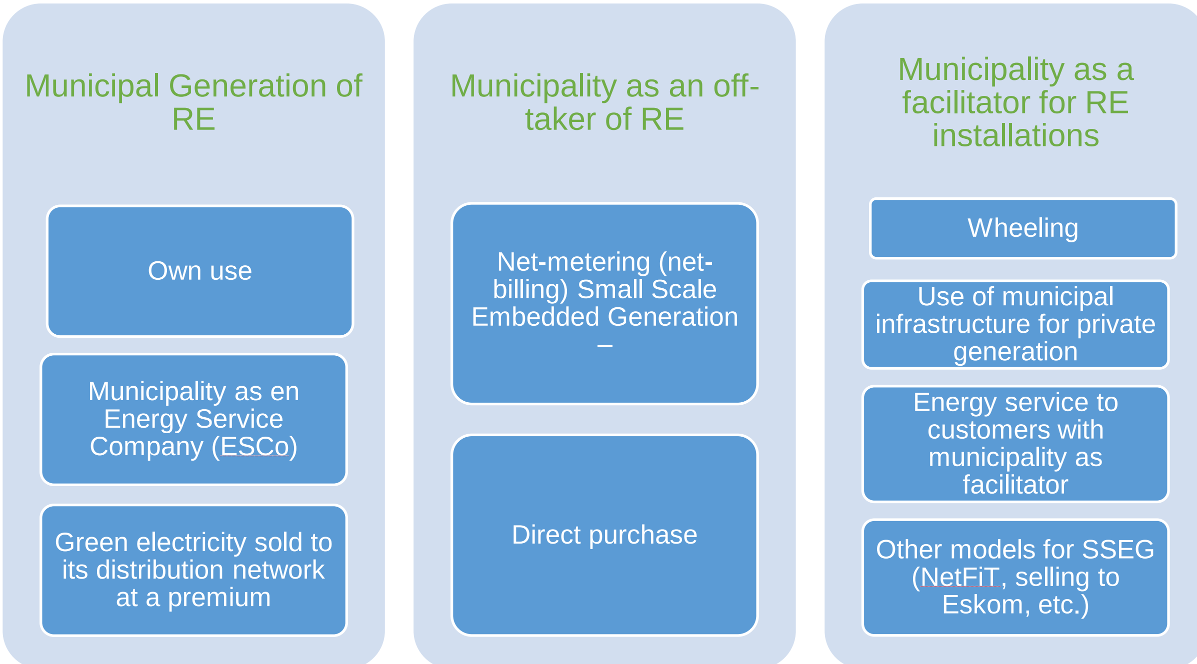
Tariff that provides an incentive for timely use of electricity

7. How should municipalities address the negative impacts of distributed PV generation on revenue if any?

- **<u>Limit impact on municipal revenue:</u>**
  - Tariffs that cover the cost of grid usage
  - Export tariff that is sufficiently low

8. Should municipalities consider the implementation of new business models in light of this transition? And what should the model entail?

Yes, municipalities should consider the implementation of new business models and SALGA has identified three listed below:



9. What is of concern in our current municipal power distribution business model?

Mostly, it is the human capital and capacity development to deal with the proliferation of these new models as well as the aged and dilapidated infrastructure that should take up the new technologies

10. Are you happy with the current regulatory approach of municipal electricity utilities?

No, and I am specifically not happy with the manner in which the tariffs are regulated where they are not reflective of the cost to do the business. Currently, NERSA regulates municipal tariffs by way of benchmarking, which is not very efficient. If we are to embrace new business models the tariffs must be as cost reflective as possible if we want the new models to make economic sense.

11. Any other comment?

No

Appendix L: Interview transcript with industry expert

Participant Interview Guide: MArch (SEEC) Research

Please note: -

- Questions below are intended to guide the interview and discussion with the participant
- Supplementary related questions may be included during the discussion; these will be documented and made available on request.
- Added questions will comply with the University's ethics guide

Questions

Information on business models (INDUSTRY EXPERT)

1. In your opinion, what do you think will be the impact on municipal finances due to increased distributed PV generation and what can municipalities do to mitigate such impact?

The impact is obvious and is loss of revenue due to not only PV but all other alternative/renewable sources of generation. Municipalities need to find ways around this by employing methods such as decoupling. It cannot be business as usual.

2. What are the relevant parameters to consider in a tariff in order to decouple revenue from sales?

Municipalities need to look at operational efficiencies and eliminate as many losses as possible through inefficiencies. These efficiencies can be improved by improving energy efficiency in municipal infrastructures, such as street lighting, building lighting etc. Addressing non-technical losses. By doing these, the municipal utility can recover huge amounts of money. Smart-grid for smart cities is another way of looking at this.

3. What is the relevance of smart-grid in distributed PV generation?

Smart-grid once implemented, can address a lot of inefficiencies, such as NTLs and TLs. Response times to an outage.

4. What role does the levelised cost of electricity (LCOE) play in the final electricity prices?

At the electricity generation level, this is a critical factor as it determines the cheapest form of energy source. Buying cheap means higher returns and affordability.

5. How can municipal power utilities improve efficiencies without compromising quality?

By implementing EEDSM, smart-grid, addressing NTLs and TLs

Appendix M: Interview transcript with Civic Groups

Participant Interview Guide: MArch (SEEC) Research

Please note: -

- Questions below are intended to guide the interview and discussion with the participant
- Supplementary related questions may be included during the discussion; these will be documented and made available on request.
- Added questions will comply with the University's ethics guide

Questions

Information on business models (OUTA)

1. Who is OUTA, and what do they represent?

This is an organization that protects consumers from tax abuse. OUTA is organization undoing tax abuse; their main focus is on protecting the consumers.

2. What is OUTA's role in the energy industry?

Mainly to protect consumers from unnecessary or unfair energy price increases, and any other seemingly unfair practices.

3. What is important for NERSA to consider when drafting registration rules for small scale embedded generators?

OUTA does not believe that the inclusion for registration of off-grid generators is fair. This places onerous requirements on consumers and municipal power utilities.

4. What should be the role of municipal distributors in managing distributed PV generation?

OUTA believe that municipalities should be allowed to generate their own power or procure their own power from any power producer.

5. Should consumers be generating their own power?

The consumer has the right to produce their own power and should be in a position to sell their excess power to the grid at agreed rates.

Appendix N: Interview transcript with Municipal officials

Participant Interview Guide: MArch (SEEC) Research

Please note: -

- Questions below are intended to guide the interview and discussion with the participant
- Supplementary related questions may be included during the discussion; these will be documented and made available on request.
- Added questions will comply with the University's ethics guide

Questions

Information on business models (MUNICIPAL OFFICIAL)

1. Do you think South Africa is on the right regulatory trajectory in terms of an embedded generation, especially PV when compared with peers and the rest of the world and what is our state of readiness?

Distributed PV systems are increasing in South Africa. However, municipalities are not ready. Most cities do not have proper frameworks to govern this. NERSA also is still in the process of developing a regulatory framework

2. Do you think the city of Ekurhuleni is paying enough attention to embedded generation installations, especially PV in terms of growth and its impact on municipal finances?

Yes, there is an embedded generation application form for registering all new installations. The city encourages project developers to register these systems; so far the registered total systems capacity is 30 MW and continues to grow. Not all project developers at this stage have registered their system.

3. How are these systems affecting CoE's revenue??

The systems registered can be used to calculate the revenue that is being lost every month, this will, however, be an estimate as it has been acknowledged that not all systems are registered. A tabular summary of the registered systems is attached.

4. What are the important factors that affect revenue in CoE of Ekurhuleni?

The demand by customers, units consumed or energy sold. This determines the energy that CoE should purchase because CoE must meet the demand. However, the city needs to purchase more units than actually required by customers because some of this energy is lost through the system. This is shown by the equation below
Sales = Eskom Purchases- losses (technical + nontechnical losses).

5. What is the city doing to counter the effect of declining sales due to increased distributed PV?

The city has introduced a fixed cost; the challenge is that I have to be introduced smoothly in order not to shock the consumers. Currently at R10. This is in an attempt to decouple revenue from sales.

6. Does CoE have historical data on electricity sales? What about data on demand, Eskom purchases and losses??

These data are available for a 10-year period, see the tables attached.

7. Has the City conducted any study aimed at determining the cost of supply as required by NERSA??

The document/study is available and was completed in the previous financial in compliance with NERSA requirements attached.

8. Is there any data available on energy efficiency projects or municipal, owned rooftop PV?

The city has installed close to 3 MW of municipal-owned rooftop PV, ground-mounted PV and landfill gas to electricity generation systems.

Appendix O: Interview transcript with NERSA official

Participant Interview Guide: MArch (SEEC) Research

Please note: -

- Questions below are intended to guide the interview and discussion with the participant
- Supplementary related questions may be included during the discussion; these will be documented and made available on request.
- Added questions will comply with the University's ethics guide

Questions

Information on business models (NERSA OFFICIAL)

1. Who is NERSA?

NERSA regulates the energy industry, and this includes electricity as it is a form of energy.

2. What role does NERSA play in distributed PV generation?

As a regulator, NERSA develops regulatory frameworks based on policies as directed by the national government of South Africa.

3. What regulatory method is currently used to regulate municipal distribution business?

The benchmarking method has always been used to regulate municipal distribution business, and this has always been done with using Eskom increase.

4. What is NERSA's view on distributed PV generation at the municipal level?

NERSA has developed a set of regulations aimed at governing the registration of small-scale embedded generators. This was withdrawn due to some concerns, such as the inclusion of normal generators, which drew outcries from the consumers, and this forced NERSA to go back to the drawing board.

5. How are municipal tariff applications evaluated?

It is only recently that NERSA started to require municipalities to conduct cost of supply studies with the aim of using this information for tariff application evaluation. NERSA has developed a framework to guide this process.

Appendix P: Interview transcript with Financier

Participant Interview Guide: MArch (SEEC) Research

Please note: -

- Questions below are intended to guide the interview and discussion with the participant
- Supplementary related questions may be included during the discussion; these will be documented and made available on request.
- Added questions will comply with the University's ethics guide

Questions

Information on business models (FINANCIER) DBSA

1. Who is DBSA?

DBSA is the development Bank of Southern Africa, provides access to finance for sustainable development of infrastructure projects. The client markets include municipalities.

2. Is there an existing market for financing of PV systems?

DBSA does finance a whole suite of developmental projects, including PV.

3. How can this market be increased?

Municipalities are not utilizing this facility as much as they should be; there needs to be an increase in access to this finance for municipal-owned projects.

4. What do you consider to be barriers to PV distributed generation in South Africa?

Municipalities see distributed PV as a disruptive technology that will erode their revenue, instead of embracing it. Municipalities should create an environment where distributed PV thrives and create methods of addressing any negative impact the growth of PV may have on them.

5. How can municipal power utilities adopt distributed PV generation without losing revenue?

Municipalities need to be proactive and be innovative and look at ways of cushioning the loss of revenue. There are various ways of doing this, including decoupling of revenue from sales, as done by the California State power utility.

6. What role can municipal power utilities play in the financing of PV systems for a distributed generation?

Municipalities have access to this finance and should be seen to be using it.

Appendix Q: Wits research ethics clearance certificate

SCHOOL OF ARCHITECTURE AND PLANNING
HUMAN RESERCH ETHICS COMMITTEE

CLEARANCE CERTIFICATE
PROTOCOL NUMBER: SOAP064/07/2018

PROJECT TITLE:	Responsive business models for municipal power utilities in a changing electricity market for South Africa: A case study of the city of Ekurhuleni
INVESTIGATOR/S:	Shandukani Tshilidzi (Student No: 523173)
SCHOOL:	Architecture and Planning
DEGREE PROGRAMME:	Masters of Architecture in Sustainable Energy Efficient Cities (MSEEC)
DATE CONSIDERED:	31 October 2018
EXPIRY DATE:	31 October 2019
DECISION OF THE COMMITTEE:	Approved

CHAIRPERSON
(Professor Daniel Irurah)

DATE: 31-10-2018

cc: Supervisor/s: Daniel Irurah

DECLARATION OF INVESTIGATORS

I/We fully understand the conditions under which I am/we are authorized to carry out the abovementioned research and I/we guarantee to endure compliance with these conditions. Should any departure to be contemplated from the research procedure as approved I/we undertake to resubmit the protocol to the Committee.

Signature

16-11-2018
Date

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