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October 2013

GUIDELINE ON THE INSTALLATION OF EMBEDDED GENERATION AND THE IMPACT IT MAY HAVE ON THE REVENUE OF MUNICIPALITIES

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1. INTRODUCTION

On 8 November 2012 the AMEU executive committee requested a work group to compile a position paper on ***the impact that embedded generation would have on the revenue from sales of electricity on municipalities***. This document serves as response to the request.

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2. ABBREVIATIONS USED IN THIS DOCUMENT

2.1. "NERSA" – means the National Energy Regulator of South Africa
2.2. "IDM programme" – means the Integrated Demand Management programme.
2.3. "PV" – means photovoltaic cells.
2.4. "SSEG" – means small scale embedded generation.
2.5. "EG" – Embedded generation.
2.6. "NRS 097- 1" – means the grid code for systems larger than 100kW.
2.7. "NRS 097- 2" – means the grid code for systems up to 100kW.
2.8. "DST 34-1665" – means Distribution Standard for the Interconnection of Embedded Generation (DSiEG): Installations 100kW – 1. MW
2.9. "DORA" – means the Division of Revenue Act
2.10. "RE" – means renewable energy.
2.11. "PFMA" – means Public Financial Management Act.
2.12. "MFMA" – means Municipal Financial Management Act.
2.13. "PPA" – means Power Purchase Agreement.
2.14. "IPP" – means an Independent Power Producer.

3. PURPOSE OF THE DOCUMENT

The exposition of the impact that distributed (embedded) generation facilities would have on the current financial position of municipalities needs to be presented within the appropriate operating framework. For that purpose this document will provide the following:

- A brief discussion of the operational aspects that need to be considered for the proper connection of embedded generation capacity to the distribution grid;

- A detailed explanation of the proposed approach to assessing the financial impact that the introduction of such EG capacity would have on municipalities;

- References to consult for further reading;

- A case study to illustrate the rigorous simulation of a variety of EG and electricity saving initiatives on a metropolitan municipality

The background to the issue of affordability to accommodate EG on a distribution grid is presented in the next section, after which the deliverables listed above will follow in sequence.

4. BACKGROUND

Municipalities and Eskom are being inundated with applications from all types of customers to allow them to install some kind of grid connected embedded generation. These applications typically include the following distributed generation alternatives:

- photovoltaic arrays
- gas powered generators that are utilised in co-generation or tri-generation arrangements
- landfill or bio-gas generation
- wind turbines
- peak filling battery inverter systems
- etc.

The reasons for developing these alternative energy sources are often cited as a method to deal with the constrained power generation of Eskom. The initiatives are also supported by Eskom in the way of reimbursing owners of embedded generators for providing alternative electrical energy resources, especially during peak consumption periods. Although the IDM programme of Eskom has suffered a financing setback with the recent reduced price escalation allowed to Eskom, the programme has been approved by NERSA. The goal of the IDM programme is to stimulate the introduction of renewable energy in order to supplement constrained electricity production capacity. EG owners can use their production capacity to either:

- reduce their load requirement from the grid – no export to the grid
- supplement own consumption requirements – intermittent export to the grid
- wheel electricity as a third party generator – constant export to the grid

EG export to the grid may be compensated for in terms of a feed-in tariff which can vary from zero to the appropriate level, or alternatively the grid may be used as energy "bank" whereby the EG producer would earn credits for own requirements at times when the EG source cannot be used, e.g. PV during night time. In addition the IDM programme has had approval from NERSA to fund renewable energy to offset own consumption and customers are requesting the option of getting credits for energy exported onto the grid. The "banking" of electrical energy is a useful concept while the EG excess production to be absorbed in the grid is small compared to the total distribution demand.

In areas where the constraint is rather due to the limitations of the local distribution network, e.g. housing estates located in areas which are reticulated for single dwelling or for agriculture supply, developers often resort to the use of peak filling inverter systems in order to supply the estates.

In general, the higher the penetration of EG in the area of supply the lower the revenue and surplus of the distributor will be. This is mainly due to the degree of sufficiency of energy supply by EG operators for own consumption. A drop in revenue, and more importantly, a reduction in surplus, can place distributors in a difficult situation when the need arises to access capital markets at reasonable costs. While it is essential for distributors to make investments in their distribution systems – investments that can enable and assist EG opportunities, as well as to ensure continued system reliability for all customers, the financing of such investments will come under pressure.

Besides the difficulty to access funds for assets maintenance, update and expansion, distributors will find it increasingly difficult to cover fixed expenses. It is important to point out that even when customers begin to generate a portion or even all of their electricity, the distributor continues to incur fixed expenses in order to provide back-up electricity service when the EG facilities aren't operating, or aren't meeting their full requirement.

The question concerning the maximum EG penetration that can be tolerated in the distributor's area of supply, under specific business model conditions will be addressed in this document.

5. ASPECTS THAT NEED TO BE CONSIDERED TO ALLOW THE CONNECTION OF EMBEDDED GENERATORS

Although a distinction is often made between large and small EG resources and that the conditions for and rules of connection to the grid may differ somewhat it is generally accepted that the following aspects need to be considered:

- Administrative issues – registration, data submission, etc.
- Safety – during installation, disconnection of islands, access to circuit breakers, etc.
- Security of the grid – system and operational protection
- Quality of supply – impact on voltage, thermal loading, harmonics and losses
- Commercial issues – metering, tariffs, etc.
- Regulatory issues – legislation, etc.

These aspects will be addressed briefly below.

5.1. Safety of staff working on the network

Embedded generation may offset own consumption but may also feed the electricity into the electricity reticulation network. This constitutes an uncontrolled point of supply to which a network or section of a network would be subjected. The safety of staff working on the grid could be at risk and cannot be compromised. Thus it would be of extreme importance that embedded generation be clearly indicated on network diagrams and on equipment in the field. Operators, electricians, and artisan assistants need to be made aware of, and trained to be on lookout for such instances.

All embedded generators would need to comply with the codes and national standards (NRS 097-2-1, DST 34-1665, SANS 10142-1 and Occupational Health and Safety Act). Contracts with self-generating customers need to ensure that all the relevant conditions are complied with. Enforcement of embedded generation policies is essential.

EG-systems connected to the grid must be able to disconnect in the event that grid supply is interrupted, in order to protect technicians who need to repair the grid. Most anti-islanding methods typically shut PV-generation down to avoid power flowing back into the grid. However, in certain instances, homeowners and small businesses may want to have the PV-system provide power as a back-up supply during grid outages. Such back-up supply would require the integration of storage and proper measures to prevent the energizing of the grid. It has to made clear to such self-generating customers what the conditions are under which they can depend on own supply during grid outages.

However, it is also important not to *overestimate* the dangers of islanding. In some countries this has led to legislation demanding very costly, or overly sensitive anti-islanding methods. From a technical point of view, including effective and reliable anti-islanding methods can be included in the inverter electronics, which makes the PV-systems simpler to install and less costly.

Maintenance procedures need to be updated and technicians need to double-check voltages, earthing, bonding, etc. before any work can commence.

5.2. Grid security and quality of supply

A number of anti-islanding methods have been developed and legislation differs in almost every country. Theoretical studies show that islanding can only happen under very special and unlikely circumstances, even when basic safety methods are implemented. These basic methods involve the monitoring of grid voltage and frequency. A control unit would, under significant change of either grid voltage or frequency, stop the PV-unit from generating electricity. These parameters can be monitored very easily and at relatively low costs through sensing circuits in the inverter electronics. Some countries such as the Netherlands, Germany, Switzerland and Austria have tried this approach and report very good success.

Power conditioning protection systems that can disconnect the EG if the voltage at the point of supply rises above the limit, are a key requirement.

Where grid connections between systems have relatively unstable quality, and where power cuts are common, the accepted voltage and frequency fluctuations need to be adjusted to accommodate these parameters. On this basis, national legislation and recommended cost-effective methods need to be developed for South Africa.

Compliance of the EG in terms of the Grid Code and NRS 097-2-1 must be proved or assured by the self-generating customer. One of the conditions for the connection agreement would be that the customer understands and accepts the need for compliance. If the EG is found to be non-compliant, the utility or distributor may retain the right to disconnect the customer. A signed certificate of compliance would ideally be required; in this regard it may be advisable to allow only approved electricians to sign these certificates.

The NRS 097-2-3 (final WG review) should eventually provide the guidelines for compliance to all the technical aspects of EG connection to the grid. Any costs associated with protecting the grid may be for the cost of the generator.

5.3. Administrative issues

It is important that EG customers comply with all municipal bylaws and for that purpose it would be beneficial to register all embedded generators. This has also been captured by NERSA in their September 2011 communique as a requirement for the connection of embedded generators to the grid.

It may also be a requirement from the municipality to register changes to building plans, e.g. when PV panels need to be installed on the roofs of buildings.

The requirements from NERSA will most likely only be in terms of licensing EG installations with capacity larger than 100 kW.

It is very important that a comprehensive Connection and Use of System Agreement be compiled and signed by both the embedded generator and the municipality that covers all aspects of the embedded generation. This should include, but not be limited to, financial terms such as the tariff that will be payable by the generator, the technical terms such as safety, quality of supply, scheduling, the maximum export capacity and the legal conditions that would apply under a breach of contract.

Note: It seems that most embedded generators are never reported to the grid operator. Enforcement of this requirement could be difficult.

5.4. Commercial issues

The energy produced by an independent generator would in most cases be incremental to existing capacity. The purchase of this energy can either be by the municipality, Eskom or another customer through a wheeling agreement.

Procurement of energy must be done in terms of the Electricity Regulation Act and the New Generation Regulations. Long term procurement has to comply with the New Generation Regulations governed by the Department of Energy, but shorter term procurement can happen subject to NERSA and PFMA or MFMA approval.

Purchase by the municipality

If any EG capacity is sold to the municipality, this reduces what they would have paid Eskom for the same energy, and provided it is at a rate equal to or lower than Eskom's energy charges, the municipality's revenue would not be impacted. This aspect will be further investigated in section 6 on the potential financial impact that EG may have on municipalities.

The contracting period and amounts will be subject to the MFMA processes and NERSA approval of the PPA.

Purchase by Eskom

If the EG capacity is sold to Eskom, it would reduce the amount of energy that municipalities would require from Eskom. Although the EG energy will flow directly into the municipality network, and will in most cases be used by municipality customers, it would be owned by Eskom.

This may lead to complexity in terms of the obligation to supply specific areas by municipality distributors. One business model that deals with the complexity allows this energy to be sold on to the municipality at the normal Eskom energy charges, excluding losses (as the municipality's network is being used). If this energy is to be produced by a co-generator, the same energy would need to be added back to the co-generator at the standard municipal rates. In this scenario the municipality could benefit as the energy added back by Eskom is at a lower rate than the standard Eskom tariffs.

Wheeling of energy

The term "wheeling of energy" is used when the energy which is produced at one point, is resold at another, but transferred over a third party grid. Wheeling of energy is allowed in terms of NERSA regulatory rules for the third party transportation of energy. Provided that the charges associated with the delivery of energy plus all administrative charges, subsidies and surcharges are raised, there should be no loss of revenue to the municipality for wheeling. Wheeling charges can also be a source of revenue for municipalities.

The aforementioned NERSA rules do, however, allow that the purchasers of the wheeled energy do not have to contribute to affordability related subsidies, which can be a cause for concern for municipalities and this would be a direct loss of revenue.

Net-metering

The common business model adopted internationally is to compensate a self-generating customer who feeds excess electricity into the grid by means of a feed-in tariff. However, it is also possible that customers would request that, rather than being paid a feed-in tariff, they be credited with the value of the excess energy produced. They could then, at a later stage when their EG production capacity is constrained (typically night-time for PV-system owners) draw from the grid the amount of energy equivalent to the value "banked". As will be indicated in section 6, this approach is feasible when the banked values are based on a tariff less than that which the customer would pay for electricity delivered from the grid. The typical tariff would be the Eskom energy charge and it may be combined with a fixed charge per kW EG capacity to the self-generating customer.

However, the customer is compensated, either by payment or in kind, bi-directional metering would have to be installed to be able to measure the exported energy.

Tariffs that could apply

Current sales tariffs of municipalities often have charges which are meant to capture fixed expenses, but all converted into a c/kWh charge.

The ideal tariff would be one where all fixed expenses are combined into a fixed charge, while the energy charges remain variable. For customers with embedded generation this could be become a necessity (refer to Eskom's Genflex tariff proposal to NERSA).

There are, however challenges with raising contribution to subsidies and surcharges where energy does not flow onto the grid i.e. cannot be measured. Mechanisms on how to manage this could include higher rates and taxes where there is generation, measuring the generator production at source and raising surcharges on this.

Note that energy efficiency initiatives have the same effect as embedded generation, i.e. customers become more energy efficient and require less energy from the municipality. The question arises whether surcharges or taxes should also be imposed on energy efficient appliances and lighting. This would appear to be unfair to consumers and encourages negative behaviour with regards to energy.

5.5. Regulatory and legal issues

There are a number of "perceived" constraints in view of possible partnerships between the embedded generator and the municipality. The most prominent ones are closely linked to the supply chain management which is governed by the MFMA on the local government level:

Legislation	**Quotation**	**Implications**
Constitution of South Africa 1996, Section 156 (1)	"A municipality has executive authority in respect of, and has the right to administer […] electricity and gas reticulation."	Gives municipalities a competency only in terms of electricity reticulation. Generation is in effect classified as a national competency. Note: There is no monopoly on electricity generation. Consumers have the right to produce their own energy or purchase it from private suppliers of energy. The municipality's rights are only to deliver energy. Distributed generation, so long as no energy is exported to the grid, does not require transportation.
Electricity Regulation Act (2006), Section 34 (1)	"The Minister may, in consultation with the Regulator […] require that new generation capacity must- (i) be established through a tendering procedure which is fair, equitable, transparent, competitive and cost-effective; (ii) provide for private sector participation."	Minister of Energy to determine who will produce, generate, procure or buy RE; no specific involvement of Municipality in these processes.
Electricity Regulation Act (2006), Section 35 (1)	"The Regulator may, after consultation with […] municipalities that reticulate electricity […] make guidelines and publish codes of conduct and practice, or make rules by notice in the *Gazette*."	Defines partial involvement of municipalities into regulation activities.
Electricity Regulation Act on New Generation Capacity	"Independent Power Producer" or "IPP" means any	Effectively implies that local government cannot hold a

(2009), Definition IPP	undertaking by any person or entity, in which the government of South Africa does not hold a controlling ownership interest (whether direct or indirect) […]"	direct or indirect controlling interest in an IPP.
Municipal Finance Management Act (2003), Section 33 (1)	"A municipality may enter into a contract which will impose financial obligations on the municipality beyond a financial year, but if the contract will impose financial obligations on the municipality beyond the three years covered in the annual budget for that financial year, it may do so only if …*(broad restrictions included*)"	Requirements for 3 year contract exemption might be difficult to fulfil, especially by smaller municipalities (category B).
Municipal Finance Management Act (2003), Section 151	"Except as expressly provided for in this Part, nothing in this Chapter limits or affects - (a) the rights of any creditor or other person having a claim against a municipality; (b) any person's access to ordinary legal process in accordance with the common law and relevant legislation; or (c) the rights of a municipality or municipal entity, or of the parties to a contract with a municipality or municipal entity, to alternative dispute resolution mechanisms, notice procedures and other remedies, processes or procedures."	Entrenches the core right of every municipality to govern its affairs at its own initiative.
Municipal Systems Act 2000, Section 85 (1)	"A municipality may [...] establish a part of the municipality as an internal municipal service district to facilitate the provision of a municipal service in that part of the municipality."	Gives a right to municipality to exercise the authority vested in it by the Constitution by means of a private company established by the municipality.
Municipal Structures Act 1998, Section 84 (1)	"A district municipality has the following functions and powers: [...] Bulk supply of electricity that affects a significant proportion of municipalities in the district."	Bulk supply of electricity is contradictory with the reticulation of electricity set in the Constitution of South Africa 1996 Section 156 (1). Bulk supply of electricity meaning transmission,

		distribution and where applicable, generation electricity.

Note: in a joint cooperation under the South African-German Energy Programme (SAGEN) the German International Cooperation (GIZ) and the South African Local Government Association (SALGA) are working towards clarifying and facilitating the necessary procedures needed for enabling distributed generation. As a first step a needs analysis study has been conducted to identify the constraints and to develop mitigating efforts.

6. POTENTIAL FINANCIAL IMPACT OF EG ON MUNICIPALITIES

In this section a simplified view of a workable business model is derived with the goal to capture most of the commercial aspects mentioned in section 5. Rather than putting forward a rigorous simulation of all the potential outcomes possible with the introduction of EG and the connection to a distribution grid, a simple generic model is derived which can be used by any municipality to assess the impact that EG would have on their financial position. In order to appreciate the mechanistic nature of the model a number of financial terms, definitions and assumptions need to be highlighted. The model will then be presented with an example worked up to illustrate its use. Finally the implications of the results will be discussed.

6.1. Useful financial terminology

The concept of a financial contribution is commonly understood as constituting the net variable revenue, i.e. the difference between variable income and variable expenses. In any financial structure the contribution, so defined, needs to be of sufficient magnitude to fund the fixed expenses and the surplus (profit).

The fixed expenses that distributors incur can broadly be defined to cover the operating overheads and financing costs, where the operating overheads may include personnel salaries, administrative expenses, depreciation and amortisation, repairs and maintenance costs and general expenses. Bad debts may be included if so desired – in the later example to illustrate the use of the model, bad debts are included. It is argued that the bad debt liability is part and parcel of the finances of the distributor as going concern and that it receives valuable management attention in the course of business. For this reason it is preferable to include bad debts under the operating overheads.

In this instance the surplus is taken to be a pre-tax amount. It is generally estimated as the difference between sales revenue and bulk purchase expenses.

It is recognised that bulk purchase costs generally include variable components, as well as semi-variable and fixed components. The variable components are energy charges, plus subsidies and levies, all of which are related to energy throughput and measured per kWh consumed. The fixed charges relate to administrative and service charges and are not related to throughput, but due to the fact of engagement between the distributor and the supplier (in this instance Eskom). The network and demand charges are normally measure per kVA capacity and can be defined to be semi-variable since there is often a significant (annual) lag in adjustment of the magnitudes.

In this exposition, however, the total bulk purchase expense is considered to be "variable". This is an approximation of reality but suits the purpose of the model as being indicative only of the true financial impact. Similarly, the total sales revenue is taken as "variable" even though it often contains a fixed service tariff, variable energy tariffs and also maximum demand tariffs that can be defined as semi-variable. The approximation of the calculated contribution is appropriate if the period used to express magnitudes of the variables is measured over a long period of time – after all, in the ultimate long run everything becomes variable. For the purpose of this model the period of measurement is taken to be a year, combined with the understanding that the energy and demand charges in the bulk purchase expense largely overshadow the fixed expenses. A similar case can be propounded for the variability of the sales revenue over a one year period.

Grants, other income and demand-side management levies that often contribute to the total revenue of distributors are ignored in this model. It may be argued that these revenue streams only act as cash sources to fund the financing charges. Although it would contribute to nature of the business of electricity distribution and reticulation, and is reflected in the income statement, it is not dependent on the sale operation per se.

6.2. Other parameters to consider

The model requires the estimation of an average price of current sales, i.e. sales before the introduction of EG. It is defined as the total annual sales revenue divided by the total amount of energy sold and can be expressed in R/kWh. Similarly, an average bulk purchase cost can be estimated from the total annual bulk purchase cost divided by the amount of energy purchased.

The difference between purchased and sold amount of energy constitutes total losses. It will also be useful to reflect the losses in terms of technical and non-technical in nature. For the purpose of the model the technical and non-technical loss rates need to be provided as (dimensionless) percentages only. Besides the view on current technical losses that may be reduced with the introduction of distributed EG, it is also necessary to state a technical loss magnitude for the EG resources. It is expected that the technical losses of the EG will increase with market penetration while the current technical losses will decline. The combined effect is simulated in the model.

The model further requires the use of a feed-in tariff for EG which will be measured in R/kWh units, as well as a fixed tariff which can be measured in the units of R/kW installed capacity (say R/kW panel for PV-installations).

In order to determine the impact of excess EG production that needs to be accommodated in the grid, it is necessary to define one more parameter, i.e. one which reflects the proportion of the excess EG capacity absorbed in the grid to the amount demanded by customers who are not self-generating, or self-generating customers that cannot supply the own needs in full.

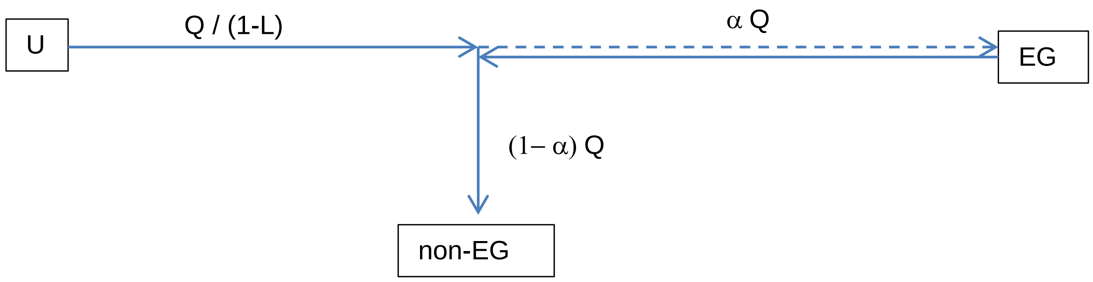
6.3. Model design

The design of the model is based on the “purchase by municipality” scenario discussed in section 5.4. Although it is derived from this scenario it can easily be adjusted to reflect the equivalent “purchase by Eskom” scenario.

Although the potential revenue reduction due to the introduction of EG is often stated as the main concern of municipalities, in this model the contribution is the main driver towards profitability. The ultimate measure is the surplus that a distributor/municipality can generate from the contribution. As soon as the surplus is depleted, the deficiency in contribution will result in the enterprise not being able to fund fixed expenses. This will lead to bankruptcy unless the municipality is propped up financially by external institutions. Self-sustainability is therefore reflected in the capability to generate a sufficiently large contribution.

For the purpose of design four entities are taken as being related, i.e. the (i) utility that usually supplies the energy which the (ii) distributor “transmits” to the customers with (iii) EG capacity and

(iv) those without (identified as non-EG, i.e. NEG). The following simple energy flow layout will assist in understanding the derivation of the model:



The derived model can be stated as:

$$\alpha \ = \frac{(1-k)}{(1+m)} \cdot \frac{\pi_0}{\pi_0 + F - G} + \frac{m}{1+m} \qquad \text{............ Eq 1}$$

With the following expansions of variables *m* and *G*:

$$m = \left[\frac{C}{1-L} - \frac{P_e}{1-L_{et}}\right] \cdot \left[\frac{r \cdot (1-L)}{P(1-L) - C}\right] \qquad \text{............ Eq 2}$$

$$G = \frac{C_e \cdot [\, \alpha \cdot (1 - L_{et} - r) + r \,] \cdot Q}{365 \cdot 24 \cdot (1 - L_{et})} \qquad \text{............ Eq 3}$$

Where

$$L = L_t(r) + L_{nt} \qquad \text{............ Eq 4}$$

$$L_t(r) = L_t \cdot [\, x \cdot (r^2 - 2r + 1) + (1-x)(1-r)] \qquad \text{............ Eq 5}$$

$$L_{et} = L_t \cdot x \cdot r^2 \qquad \text{............ Eq 6}$$

The parameters are defined as follows:

α = penetration of EG in the total market, indicated by the percentage of the total market that can be supplied from actual self-generation production capacity

1 - k = the total loss in surplus that could be tolerated, with 0 < k < 1

π_0 = the current surplus (R/a)

F = total annual fixed expenses (R/a)

C = average total bulk purchase cost (R/kWh)

P = average overall sales price (R/kWh)

Q = total energy delivery under conditions without EG (kWh/a)

P_e = average feed-in tariff to be paid for excess EG production (R/kWh)

C_e = average fixed charge to EG for connection to the grid (R/kW/a)

L = total losses (% of bulk purchase)

L_t = overall technical losses under conditions without EG (% of bulk purchase)

L_{nt} = overall non-technical losses under conditions without EG (% of bulk purchase)

L_{et} = technical losses from supply by EG (% of excess EG production absorbed by the grid)

x = variable fraction of overall technical losses

r = the ratio of excess EG production absorbed in the grid to the total demand by non-EG consumers

$L_t(r)$ = overall technical losses under conditions with EG (% of bulk purchase)

Equation 1 is structured to indicate the proportion of total current energy supply that can be supplied by EG producers for own use. This can be seen as the "maximum penetration" of EG in the current market that can be tolerated at the proposed feed-in tariff and fixed charge on total installed EG capacity. In this form it is required to provide the loss in (current) surplus that may be tolerated by the municipality, eg. if a loss of 25% can be tolerated, then (1 – k) = 0.25

If so preferred, equation 1 can be rewritten to allow the loss in surplus to be the dependent variable:

$$(1-k) = [\alpha \cdot (1+m) - m] \cdot \frac{\pi_0 + F - G}{\pi_0} \qquad \text{............ Eq 7}$$

In this instance it would be required to take a view on the EG penetration level that would apply, eg. at an assumed penetration level of 15%, it is necessary to set $\alpha = 0.15$

For the convenience of the reader, this model has been coded in MS Excel and will be provided on a CD with the report. It can also be obtained from Dr DJ Marais at *danielm@macgroup.co.za* or Mr Gerrit Teunissen at *gteunissen@citypower.co.za*.

It would be required to allow iterative calculations in Excel by ticking the box "*Enable iterative calculation*" in the *File >> Options >> Formulas* dialog box.

The interested reader can obtain the derivation of the model (equations 1 through 7) from Dr DJ Marais at *danielm@macgroup.co.za*

6.4. Example to illustrate the use of the model

The following information would be required as input to the model:

- Total energy demand, including the demand of self-generating customers, measured in kWh per annum
- Total sales revenue derived from delivery on the total demand estimated above, measured in R per annum
- Total bulk purchase cost, measured in R per annum
- Total bulk purchase energy amount, measured in kWh per annum
- The current fixed expenses, measured in R per annum
- The total technical losses of the distribution system, as a percentage
- The total non-technical losses associated with the distribution business, as a percentage

Note that this information can be obtained quite easily from the distributor's financial and management accounts.

It is also required to have a view on the following information which relates to the introduction of EG to the grid:

- Total loss in surplus that can be tolerated by the municipality, as a percentage
- The variable component of technical losses, which typically ranges from two-thirds to three-quarters of the total technical losses
- The proportion of the non-EG demand that would be supplied by excess EG production which is fed back into the grid
- The feed-in tariff that could be offered to EG producers
- The average fixed charge that would apply to EG producers

The case of City Power is selected here to illustrate the use of the model. The purpose is to determine the maximum EG penetration levels that can be allowed at certain given financial and operating conditions.

The following information items were collected from their FY2013/14 budget:

- Total energy demand:
  Q = 11 421 953 273 kWh/a
- Total sales revenue of R13 276 318 285, from which the average sales price is determined to be:
  P = 13 276 318 285 / 11 421 953 273 = R1,162 per kWh
- Total bulk purchase cost of R 9 608 989 845 for the year
- Total bulk purchase energy amount of 13 225 402 889 kWh/a, from which the average bulk purchase cost is estimated to be:
  C = R 0,727 per kWh
- The current fixed expenses are R 3 266 747 000 for the year:
  F = R 3 266 747 000
- The current surplus level is estimated to be:
  π_0 = 13 276 318 285 – 9 608 989 845 – 3 266 747 000 = R400 581 440
- The total technical losses of the distribution system is generally assumed to be:
  L_t = 9%
- The total non-technical losses associated with the distribution business is estimated to be:
  L_{nt} = 4,6%

The following views would apply:

- Total loss in surplus that can be tolerated by the municipality is assumed to be 100%, i.e.
  (1 – k) = 1,00
  This will indicate the absolute maximum EG penetration that could be allowed before City Power runs into the situation where fixed costs cannot be paid anymore.
- The variable component of technical losses is assumed to be two-thirds of the total technical losses, i.e.
  x = 0,667
- The proportion of the non-EG demand that would be supplied by excess EG production which is fed back into the grid is assumed to be 10%, i.e.
  r = 0,10
- The feed-in tariff allowed is assumed to be the same as the average cost of the bulk purchase, i.e.
  P_e = C = R 0,727 per kWh
- No fixed charge is applied, i.e.
  C_e = R 0,00/kW installed per year.

This yields the worst case scenario for City Power.

If these values are plugged into the model to estimate the parameters L_{et}, $L_t(r)$, L, G and m from equations 2 to 6, the maximum allowed EG penetration (α) can be estimated from equation 1. Note that G is also dependent on α; the values for G and α thus need to estimated iteratively. Once the iterative calculation reaches equilibrium, it is found that City Power can allow 13,5% of the current market capacity in its area of supply to be eliminated by the installation of EG for own use.

As a sensitivity, one could require a fixed EG charge to apply, such that C_e = R1 606/kW/a, which amounts to R4,40/kW/day. This fixed income would equate to the total expected expenditure on repair & maintenance for the year and will thus reduce the total fixed expenses to be funded from the contribution by that amount. The maximum EG penetration that can then be allowed in this case would be 15,2% of current market capacity.

As a further sensitivity, one could assume all of the above conditions and adjust the feed-in tariff to zero, i.e. P_e = R 0,00/kWh. This scenario will yields a maximum allowable EG penetration of 31,0%.

A general view on the variety of scenarios that could be generated by further adjusting the maximum allowed loss in surplus and the feed-in tariff can be illustrated in a sensitivity table (Table 1).

SENSITIVITY ANALYSIS

Maximum EG penetration that can be allowed when loss in surplus is limited at various feed-in tariffs

	Loss in surplus that can be tolerated by municipality										
Feed-in tariff to offer (R/kWh)	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%	0%
0.00	31.0%	29.8%	28.6%	27.4%	26.3%	25.2%	24.1%	23.0%	21.9%	20.8%	19.8%
0.05	30.1%	28.9%	27.7%	26.5%	25.4%	24.2%	23.1%	22.0%	20.9%	19.9%	18.8%
0.10	29.1%	27.9%	26.7%	25.6%	24.4%	23.3%	22.2%	21.0%	20.0%	18.9%	17.8%
0.15	28.2%	27.0%	25.8%	24.6%	23.4%	22.3%	21.2%	20.0%	19.0%	17.9%	16.8%
0.20	27.2%	26.0%	24.8%	23.6%	22.4%	21.3%	20.1%	19.0%	17.9%	16.8%	15.8%
0.25	26.2%	25.0%	23.8%	22.6%	21.4%	20.2%	19.1%	18.0%	16.9%	15.8%	14.7%
0.30	25.2%	23.9%	22.7%	21.5%	20.3%	19.2%	18.0%	16.9%	15.8%	14.7%	13.6%
0.35	24.1%	22.9%	21.7%	20.4%	19.3%	18.1%	16.9%	15.8%	14.7%	13.6%	12.5%
0.40	23.0%	21.8%	20.6%	19.3%	18.1%	17.0%	15.8%	14.6%	13.5%	12.4%	11.3%
0.45	21.9%	20.7%	19.4%	18.2%	17.0%	15.8%	14.6%	13.5%	12.3%	11.2%	10.1%
0.50	20.8%	19.5%	18.3%	17.0%	15.8%	14.6%	13.4%	12.3%	11.1%	10.0%	8.9%
0.55	19.6%	18.3%	17.1%	15.8%	14.6%	13.4%	12.2%	11.0%	9.9%	8.8%	7.6%
0.60	18.4%	17.1%	15.8%	14.6%	13.4%	12.1%	11.0%	9.8%	8.6%	7.5%	6.3%
0.65	17.1%	15.8%	14.6%	13.3%	12.1%	10.9%	9.7%	8.5%	7.3%	6.1%	5.0%
0.70	15.9%	14.6%	13.3%	12.0%	10.8%	9.5%	8.3%	7.1%	5.9%	4.8%	3.6%
0.75	14.5%	13.2%	11.9%	10.7%	9.4%	8.2%	6.9%	5.7%	4.6%	3.4%	2.2%
0.80	13.2%	11.8%	10.5%	9.3%	8.0%	6.8%	5.5%	4.3%	3.1%	2.0%	0.8%
0.85	11.8%	10.4%	9.1%	7.8%	6.6%	5.3%	4.1%	2.9%	1.7%	0.5%	-0.7%
0.90	10.3%	9.0%	7.6%	6.3%	5.1%	3.8%	2.6%	1.3%	0.1%	-1.1%	-2.2%
0.95	8.8%	7.5%	6.1%	4.8%	3.5%	2.3%	1.0%	-0.2%	-1.4%	-2.6%	-3.8%
1.00	7.3%	5.9%	4.6%	3.2%	2.0%	0.7%	-0.6%	-1.8%	-3.1%	-4.3%	-5.5%

Table 1: EG penetration, while providing 10% of non-EG demand from EG producers, with fixed EG charge of R4,40/kW/day

Naturally, negative values for the EG penetration would be meaningless and these are indicated in yellow. These values would indicate infeasible scenarios where the fixed expenses cannot be funded from contributions while maintaining the required surplus levels.

From Table 1 it is possible to find the 15,2% maximum EG penetration that can be allowed mentioned above. In the column indicating the allowed surplus loss of 100%, and the row indicating a feed-in tariff of 70c/kWh, it is found that the maximum EG penetration would be 15,9%. Similarly, in the 100% column and the row indicating a feed-in tariff of 75c/kWh, the maximum EG penetration is found to be 14,5%. The value actually used for P_e was 72,7c/kWh, which falls between 70c/kWh and 75c/kWh. The estimated value of 15,2% would thus be obtained from interpolating between the 14,5% and 15,9% read from the table.

Note that similar tables can be obtained from the Excel model that accompanies this guideline report by simply changing the input conditions.

6.5. Further implications of example results

As indicated above, the model was derived for the case reflecting the purchase of EG capacity by the municipality. If the EG capacity would be purchased by the utility supplier (Eskom), and the excess EG production sold on to the distributor at marginal value (energy charge only), it can be interpreted as a determinant of the P_e-value for the distributor.

In City Power's case it would have amounted to a P_e of R0,44/kWh to R0,45/kWh, which would have been less than the initially assumed average bulk purchase tariff of R0,727/kWh. From Table 1, assuming an allowed total loss of surplus, the maximum EG penetration would have increased from 15,2% to 21,9% at a feed-in tariff of R0,45/kWh. If the feed-in tariff is maintained at R0,45/kWh, the maximum allowable EG penetration of ~15% can be obtained at an allowed loss in surplus of ~45% (interpolated between the columns for 40% and 50% in the table). Thus, by reducing the feed-in tariff, one can obtain a similar EG penetration limit while the surplus loss is reduced from 100% to about 45%.

It should be noted that the impact of energy saving devices can also be addressed in the above model. In such cases, there is no feed-in of excess production to be expected ($r = 0$), no feed-in tariff or EG fixed charges would apply ($P_e = 0$, $C_e = 0$).

From a given (assumed) maximum penetration of the potential market demand (which excludes energy saving devices), the implied losses can be determined by using equation 7 rather than equation 1 above, as these two equations express the same identity, just in different formats.

6.6. Supplementing the model

Even though the above model is based on averages and assumptions concerning the variability of sales revenue and bulk purchase costs, it can already provide a reasonable proxy of what can be expected from the introduction of EG in the supply areas of distributors. It utilises a delayed time dimension and yields results that could drive broad strategic decision-making.

However, the model is not meant to be used when evaluating specific operational or financial investment decisions, eg. price negotiations with EG producers. In such cases it would be prudent to work up cash flow cases as provided by Trollip (2012) and SEA in appendix A. Such models are of a simulation type and can be made quite rigorous, reflecting the real scenario at hand. Very short unit time dimensions can also be employed in such cases, i.e. one can typically determine the impact rigorously over periods ranging from days to years.

7. CONCLUSIONS

As the price of electricity escalates in South Africa while supply constraints remain, it becomes lucrative for customers to implement energy saving and self-generating capacity. This will result, not only in a reduction of the footprint of supply by distributors, but will also require the accommodation of excess electricity produced by such self-generating customers. The fact that embedded generation cannot necessarily be offered at a consistent level (PV installations) complicates the situation for the distributors as the grid facility cannot be reduced if customers need to draw from and supply to the distribution system.

Safety is of paramount importance when connecting distributed generation capacity to the grid and compliance to various codes will have to be enforced.

Security and the quality of grid supply cannot be compromised by connecting EG to allow feeding in of excess production and need to be monitored diligently.

A variety of “perceived” constraints in view of possible partnerships between the embedded generator and the municipality are governed by the MFMA on the local government level. The distributor needs to consider a host of legislative aspects that would regulate the incorporation of EG in the current distribution system management.

The commercial aspects relating to the introduction of EG into the distribution system culminates in the financial impact it would have on the profitability of municipalities. Strategic decisions by distributors and municipalities will be driven by the business impact that EG would have on operations and the financial situation. For that purpose it is required that an assessment of the potential financial impact be made available to guide the focus when negotiating prices with EG owners and designing business models for the future which will ensure the quality and availability of the distribution networks. A simplified model has been provided whereby municipalities can assess their own vulnerability.

A variety of tariff models can be accommodated, ranging from the “banking” of energy value to a simple feed-in tariff for excess EG production. The introduction of a fixed tariff relating to the installed EG capacity has also been addressed.

This provides a means of quantifying the portion of surplus lost through embedded generation and energy efficiency measures within a municipality. The calculation could be audited by an independent third party, following on which a request for a financial allocation (in line with the calculated figure) could be made to National Treasury. Equivalent financial support could thus be provided to the affected municipality through, for example, the National Treasury led 'Cities Support Programme'. Allocations could also be made directly through the Division of Revenue Act (DORA) on an annual basis, in order to compensate municipalities for lost revenue.

National Treasury is supporting a programme of 'environmental fiscal reform' in South Africa, and is also concerned about the cost of new coal-fired powers stations in South Africa, and thus may be in favour of such an approach.

By adopting this overall method, municipalities can support embedded generation, overall electricity system health and economic growth, while being provided equivalent financial assistance for infrastructure development and other key programmes.

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9. APPENDIX A

Case Study: Impact of localised Energy Efficiency (EE) and Renewable Energy (RE) on City Power finances over the next 10 years

Prepared by

Sustainable Energy Africa

with funding from

renewable energy & energy efficiency partnership

September 2013
DRAFT

10. CONTENTS

11. EXECUTIVE SUMMARY

This case study determines the potential impact of energy efficiency (EE) and renewable energy (RE) interventions on City Power's revenue base. This is important information for municipal electricity utilities to understand, due to the rapidly increasing uptake of these EE and RE technologies in the residential, commercial and industrial sectors over the last 5 years, and the anticipated increased uptake into the future.

While the benefits of RE and EE interventions include a more resource efficient, low carbon economy, and a degree of decoupling of economic growth and energy growth, there is another side to consider. Surplus revenues from municipal electricity departments typically cross subsidise other services, and ensure that municipalities as a whole continue to function effectively. Therefore any loss of electricity sales can have a knock on effect on overall service delivery of a municipality.

While the uptake of RE and EE interventions such as solar water heaters and heat pumps, photovoltaic panels, efficient lighting, efficient HVAC and efficient motors will come as a matter of course, it is important for municipal management to understand their potential future impact on City finances, so that the situation can be effectively managed. This case study has quantified these losses, firstly by determining potential market uptake per intervention over the next ten years, and then accurately determining their financial impact using an Excel based spreadsheet electricity savings and financial impact model. This model has been developed by Sustainable Energy Africa with funding from REEEP in partnership with four municipalities – City Power, Ekurhuleni, eThekwini and Cape Town. It's credibility has been vetted by these municipalities, and it is considered scientifically sound.

The results of this exercise for City Power can be summarised as follows:

A 10 year RE and EE uptake projection exercise for the City Power customer market showed that large scale SWH and EE uptake is likely within this period. PV uptake will be slower due to a less attractive financial case. However from year 5 commercial customers can benefit immediately from a financed PV solution, and from year 10 the same is expected to apply to residential and industrial customers.

The table below provide a summary of the RE and EE projections by year 10, and their respective impact on City Power's total revenue

Impact of RE and EE on City Power revenue after 10 years					
	Customers above 600kWh/month	PV uptake by year 10	SWH uptake by year 10	EE uptake by year 10	Impact on revenue
Residential	269169	44221	160639	160639	-R 558 231 401
Commercial	7335	4148	0	500	-R 281 823 107
Industrial	4005	674	0	2332	-R 305 886 623
					-R 1 145 941 131

The following table shows the same data but by percentage

Impact of RE and EE on City Power revenue after 10 years by percentage					
	Customers above 600kWh/month	PV uptake by year 10	SWH uptake by year 10	EE uptake by year 10	Impact on revenue
Residential	269169	16%	60%	60%	-1.11%
Commercial	7335	57%	0%	7%	-0.56%
Industrial	4005	17%	0%	58%	-0.61%
					-2.28%

This information shows that under Business as Usual (BAU) conditions, ie no major changes to tariff structures over the next 10 years, EE and RE will decrease City Power's revenue base **by 2.28%.** The residential sector is responsible for approximately 50% of the losses, while the commercial and industrial sectors account for approximately 25% each. This is a substantial figure, and municipal management will need to come up with strategies to absorb the loss.

A sensitivity analysis using was performed on these figures which indicated that the losses could be as low as 1.5% if the projected uptake of PV and SWHs is halved, or as much as 3.6% if the projected uptake of these components is doubled. A 0% increase in electricity sales into the future increases the revenue impact to 3.1%.

The case study also shows that losses can be managed through strategies such as implementing fixed daily charge for grid connected PV systems with an accompanying decreased energy charge, or by implementing a residential Time of Use (ToU) tariff.

This case study shows that the potential future impact of RE and EE on municipal finances is significant, and will continue to grow with time. Clearly management strategies will need to be developed into the future to accommodate these losses.

It should be noted that the tool developed to calculate the impact of RE and EE on municipal finances is freely available from Sustainable Energy Africa. It can be easily modified to apply to municipalities other than those already modelled. For more information please contact us by email at andrew@sustainable.org.za or at 021-7023622.

Sustainable Energy Africa is a not-for-profit organization supporting cities and other institutions with sustainable energy transitions

12. OVERVIEW OF ISSUE

Over the past 5 years, the market for energy efficient products in the lighting, water heating, HVAC, electric motor, variable speed drive and power factor correction products has increased significantly. At the same time there has been a marked increased interest from residential and commercial sector in installing rooftop photovoltaic panels (PV) for own use.

This increase in uptake has been a result of

1. rapidly increasing electricity prices due to Eskom's new build programme for two more coal fired power stations – Kusile and Medupi.
2. Eskom's increased efforts to implement demand side management (DSM) to assist in relieving the pressure from the grid. This has been implemented through several financial incentive schemes to encourage uptake of EE products in the residential, commercial and industrial sectors.
3. Increased awareness raised through electricity savings campaigns run by Eskom, local and national government.

These factors, coupled with a slower economy, have made a marked impact on levels of electricity use in South Africa. For the first time in 2012/3, annual electricity usage for the country dropped, and several Metro electricity departments have reported a drop in electricity sales over the last 1 to 4 years. Also for the first time, analysts are seeing that economic growth is increasing within the context of this lack of electricity growth, implying a degree of decoupling of these two indicators which in the past were joined at the hip. While this situation must be viewed positively from a sustainable development perspective due to a more efficient economy, reduced impact on natural resources and a low carbon growth path, there is another condition to consider:

In South African cities, the distribution of electricity to customers is a function of local government, and to a smaller degree Eskom. Local government finances have been set up in such a way that surplus income from their electricity service (and to a smaller degree their water service) is needed to balance the municipal books. Figure 1 below indicates this graphically for a typical municipality. The red line is the rates account, which does not cover the costs of running the municipality's other functions. Electricity and water effectively cross subsidise these. Many of these functions are linked to poverty alleviation and social upliftment and include: health clinics, housing, refuse removal, waste water removal, public lighting, roads and public recreation areas.

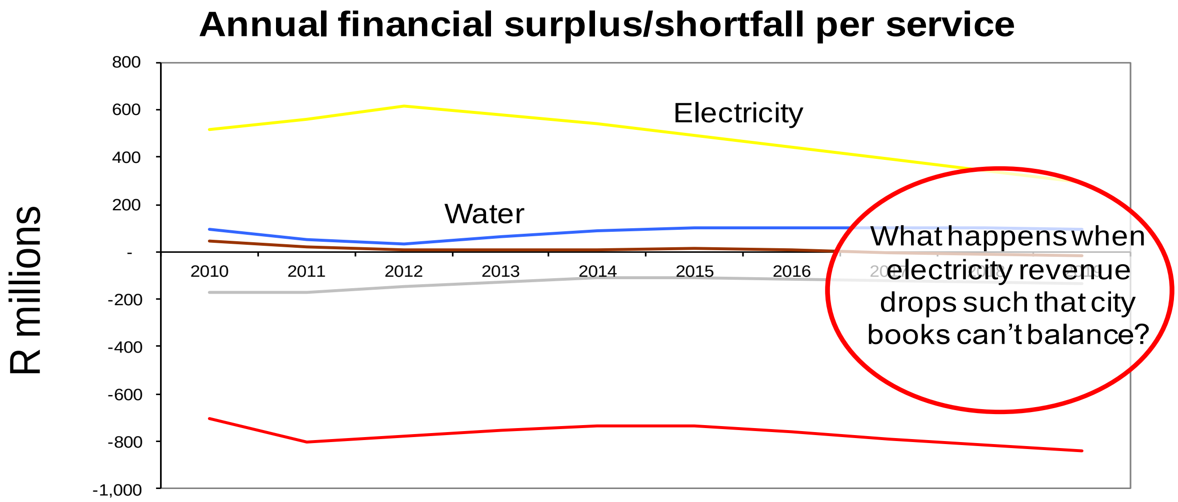
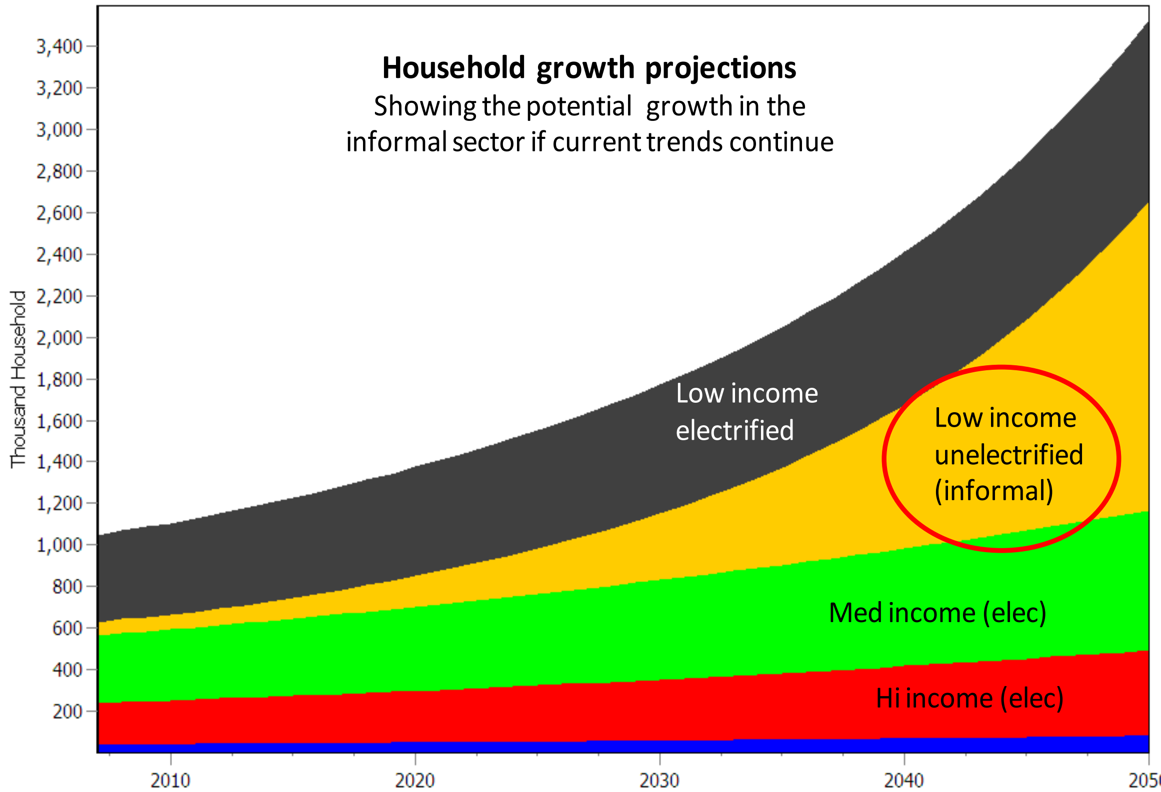


Figure 1

Furthermore, informal settlements are growing in South African Cities, and there is increasing pressure for local government to provide safe electricity to these communities at subsidised rates.



The question which arises then is: If electricity revenue drops as a result of increased uptake levels of RE and EE in the residential, commercial and industrial sectors, while there is an increased demand for subsidised low income electrification into the future, what will the overall impact be on service delivery within a municipality?

This report sets out to answer this question using City Power as a case study

13. TECHNOLOGY UPTAKE

In order to understand the potential uptake of RE and EE technology in the City Power distribution area, the market size and the financial case for each of the interventions needs to be considered. For market size, we will use a summary assessment of current

City Power customers. The financial case will be based on a technology cost benefit analysis.

Market for RE and EE Technology and uptake projections

When considering the market potential for RE and EE uptake, this case study will only consider residential, commercial and industrial customers who currently consume over 600kWh per month. Any customer consuming lower than this figure is not using large amounts of electricity. This could be due to budget constraints or to the customer operating the premises efficiently already. As a result of these factors, this customer will in all likelihood not consider RE and EE interventions, due to the minimal savings that they will provide, or due to the additional upfront costs. Typically, uptake is expected to come from the higher end of the consumption market, where savings can be realised, and where there is the financial capacity to implement.

In this light, a summary of the current City Power customers consuming above 600kWh per month is presented below:

Customer sector	Customers	Blended Tariff in cents (inc VAT)
Domestic (prepaid meter)	**165 353**	
600-1000	73 867	114.47
1000-2000	68 267	121.88
2000-3000	13 503	134.82
>3000	9 716	144.56
Domestic 1 ph (credit meter)	**83 003**	
600-1000	37 028	110.64
1000-2000	36 141	113.01
2000-3000	6 669	115.76
>3000	3 165	117.15
Domestic 3 ph (credit meter)	**20 813**	
600-1000	5 536	110.64
1000-2000	5 076	113.01
2000-3000	1 309	115.76
>3000	1 801	117.15
Business (0-50kVA)	**7 091**	
600-1000	1 218	172.17
1000-2000	1 785	176.19
2000-3000	2 004	178.70
>3000	2 084	179.91
Industrial LV	**3 757**	99.41
Industrial MV	**231**	93.45

Source: D. Marais, 2013

From this table it can be seen that there are approximately 270 000 potential residential, 7000 commercial and 4000 industrial customers who could consider implementing EE and RE interventions if they make financial sense.

Financial cases for interventions by technology

SEA has undertaken a range of EE and RE intervention cost benefit analyses. These determine the financial payback of each intervention, taking the following factors into consideration:

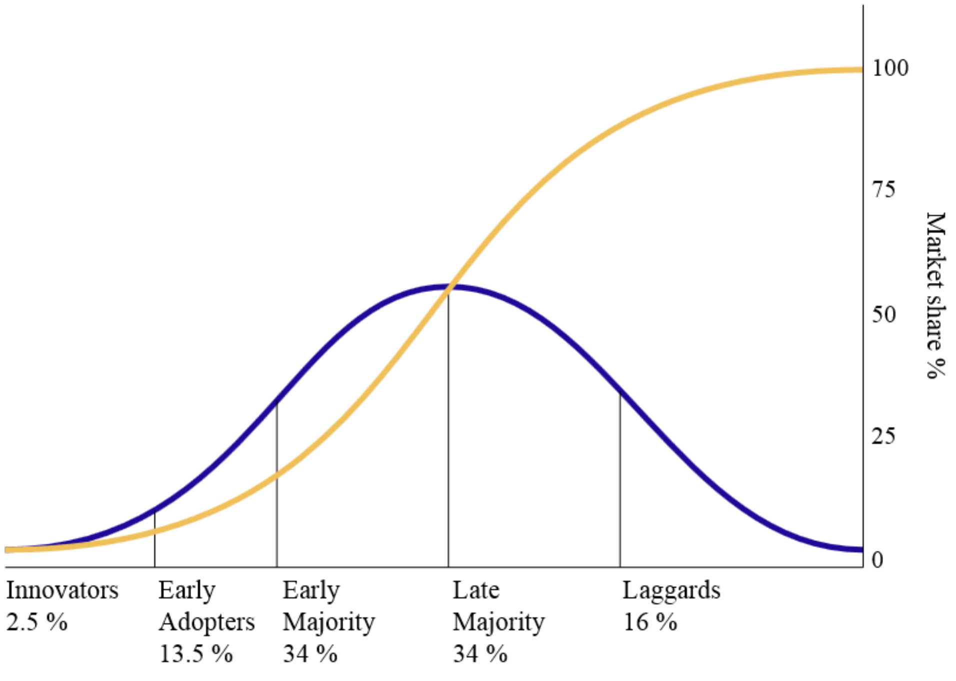
i. Full installed cost of intervention

ii. Current tariff specific to sector (residential, commercial, industrial)
iii. Tariff increase of 8% per year
iv. Financial attractiveness of the intervention to the end user based on
   a. Cash up front repayment
   b. bond repayment (8.5% interest over 10 years)
   c. retail bank loans (18% over 5 yrs)

An intervention which should enjoy market uptake is assumed to be either

i. one which pays back in under 3 years or
ii. one which can be financed to achieve net savings within the first few years of installation ie monthly finance repayment costs are equal to or less than energy savings from the intervention

Market uptake of an RE or EE intervention will be based on a generic Rogers distribution curve (blue curve in graph below). The innovators (2.5% of the market) and early adopters (13.5% of the market) will typically install the intervention prior to the intervention making financial sense, while the early majority (34%), late majority (34%) and laggards (16%) will implement once the intervention is mainstreamed and the financial barriers have been overcome. Once the laggards have adopted the technology, the market share will be considered to be saturated (yellow curve below)



Full detailed financial spreadsheets are available on request from Sustainable Energy Africa, but for the sake of this report a summary table of payback periods per intervention is provided below:

Photovoltaics (PV)

The analysis table below shows that the financials for photovoltaics are not currently meeting mass market uptake requirements. Depending on the customer sector, energy use profile and method of financing, payback can be anywhere from 7 to 15 years for an installed system.

		Year in which intervention total savings exceed total costs		
		Install now		
Customer sector	**Customers**	**18% loan over 5 yrs**	**8.5% loan over 10 years**	**Cash up front**
Domestic (prepaid meter)	**165 353**			
600-1000	73 867	14	13	10
1000-2000	68 267	13	13	9
2000-3000	13 503	12	12	9
>3000	9 716	12	11	8
Domestic 1 ph (credit meter)	**83 003**			
600-1000	37 028	14	14	10
1000-2000	36 141	14	13	10
2000-3000	6 669	13	13	10
>3000	3 165	13	13	10
Domestic 3 ph (credit meter)	**20 813**			
600-1000	5 536	14	14	10
1000-2000	5 076	14	13	10
2000-3000	1 309	13	13	10
>3000	1 801	13	13	10
Business (0-50kVA)	**7 091**			
600-1000	1 218	10	8	7
1000-2000	1 785	10	8	7
2000-3000	2 004	10	8	7
>3000	2 084	10	8	7
Industrial LV	**3 757**	15	15	11
Industrial MV	**231**	15	15	11

However, these figures are not indicative of how potentially close mass PV uptake in the market is. Creating attractive financing solutions such as placing the capital cost of the intervention onto a home loan (the 8.5% over 10 years scenario) can bring the annual loan repayment very close to the annual energy saved amount. It is also useful to project the financial attractiveness over the next 5 and 10 year window periods. These results are presented in the tables below:

Present day window assessment of PV financial viability by sector

Customer sector	Customers	8.5% loan over 10 years	Max monthly loss/kWp
Domestic (prepaid meter)	**165 353**		
600-1000	73 867	13	R 165
1000-2000	68 267	13	R 154
2000-3000	13 503	12	R 134
>3000	9 716	11	R 118
Domestic 1 ph (credit meter)	**83 003**		
600-1000	37 028	14	R 171
1000-2000	36 141	13	R 167
2000-3000	6 669	13	R 163
>3000	3 165	13	R 161
Domestic 3 ph (credit meter)	**20 813**		
600-1000	5 536	14	R 171
1000-2000	5 076	13	R 167
2000-3000	1 309	13	R 163
>3000	1 801	13	R 161
Business (0-50kVA)	**7 091**		
600-1000	1 218	8	R 75
1000-2000	1 785	8	R 69
2000-3000	2 004	8	R 65
>3000	2 084	8	R 63
Industrial LV	**3 757**	15	R 188
Industrial MV	**231**	15	R 198

This table shows that residential customers who install a PV system in Joburg through their bonds (over 10 years) would only be paying an additional monthly cost of R118 – R171 per kWp system installed in year 1. From then on the additional monthly cost will decrease year on year as savings increase due to increased electricity prices.

Under the same loan conditions, business customers that install a PV system in Joburg stand to pay a maximum of R63-R73 per month extra per kWp, while industrial customers stand to pay R188-R198 per kWp.

This is not a large additional outlay, and may attract several **early adopters** of the technology over the next five years, particularly those with a long term outlook on their property. PV systems keep working for at least 25 years, and will more than pay for themselves over this period.

Five year window assessment of PV financial viability by sector

Looking at the same idea in five years' time, when the electricity price has increased and the price of PV has decreased, in line with current trends, the following results are apparent:

Customer sector	Customers	8.5% loan over 10 years	Max monthly loss/kWp in todays' rands
Domestic (prepaid meter)	**165 353**		
600-1000	73 867	12	R 84
1000-2000	68 267	11	R 72
2000-3000	13 503	10	R 52
>3000	9 716	8	R 37
Domestic 1 ph (credit meter)	**83 003**		
600-1000	37 028	11	R 90
1000-2000	36 141	11	R 86
2000-3000	6 669	11	R 82
>3000	3 165	11	R 80
Domestic 3 ph (credit meter)	**20 813**		
600-1000	5 536	11	R 90
1000-2000	5 076	11	R 86
2000-3000	1 309	11	R 82
>3000	1 801	11	R 80
Business (0-50kVA)	**7 091**		
600-1000	1 218	1	-R 6
1000-2000	1 785	1	-R 12
2000-3000	2 004	1	-R 16
>3000	2 084	1	-R 18
Industrial LV	**3 757**	12	R 107
Industrial MV	**231**	13	R 117

Domestic customers can still expect to pay a small additional monthly fee (R37-R90) per kWp per month, approximately 50% less than the present day scenario. Likely customers will still fall into the early adopter category (13.5% of the market), as immediate financial benefits will not be realised.

Similarly industrial customers will still be paying an additional monthly fee of R107-R117 per kWp per month.

However, by year five businesses customers will find immediate savings from installing a PV system using finance (ie monthly repayments are lower than electricity savings). This will signal conditions acceptable for the **early majority** of consumers (typically 34% of the market).

Year 10 window assessment of PV financial viability by sector

Looking at the same idea in ten years' time, when the electricity price has increased and the price of PV has further decreased, in line with current trends, the following results are apparent:

Customer sector	Customers	8.5% loan over 10 years	Max monthly loss/kWp in todays' rands
Domestic (prepaid meter)	**165 353**		
600-1000	73 867	6	R 26
1000-2000	68 267	4	R 14
2000-3000	13 503	1	-R 6
>3000	9 716	1	-R 21
Domestic 1 ph (credit meter)	**83 003**		
600-1000	37 028	5	R 32
1000-2000	36 141	5	R 28
2000-3000	6 669	5	R 24
>3000	3 165	5	R 22
Domestic 3 ph (credit meter)	**20 813**		
600-1000	5 536	5	R 32
1000-2000	5 076	5	R 28
2000-3000	1 309	5	R 24
>3000	1 801	5	R 22
Business (0-50kVA)	**7 091**		
600-1000	1 218	1	-R 64
1000-2000	1 785	1	-R 70
2000-3000	2 004	1	-R 74
>3000	2 084	1	-R 76
Industrial LV	**3 757**	10	R 49
Industrial MV	**231**	11	R 58

By year 10 domestic and industrial customers are right on the borderline of financial viability, and should mark the beginning of the **early majority phase** of market uptake (34%).

Business customers will have been viable financially for 5 years, and with an even more attractive financial proposition should be well into the **late majority phase** of the market (34%) by year 10.

Based on these calculations, the following PV market uptake is projected for Joburg over the next 10 years:

- Approximately 45000 PV systems in the residential market
- Approximately 4000 PV systems in the commercial market
- Approximately 670 PV systems in the industrial market

		5 year	10 year
Customer sector	Customers	Projected uptake by 2017/18	Projected uptake by 2022/23
Domestic (prepaid meter)	**165 353**	**9781**	**27945**
600-1000	73 867	4369	12484
1000-2000	68 267	4038	11537
2000-3000	13 503	799	2282
>3000	9 716	575	1642
Domestic 1 ph (credit meter)	**83 003**	**4910**	**14028**
600-1000	37 028	2190	6258
1000-2000	36 141	2138	6108
2000-3000	6 669	394	1127
>3000	3 165	187	535
Domestic 3 ph (credit meter)	**20 813**	**812**	**2319**
600-1000	5 536	327	936
1000-2000	5 076	300	858
2000-3000	1 309	77	221
>3000	1 801	107	304
Business (0-50kVA)	**7 091**	**1452**	**4148**
600-1000	1 218	249	713
1000-2000	1 785	365	1044
2000-3000	2 004	410	1172
>3000	2 084	427	1219
Industrial LV	**3 757**	**222**	**635**
Industrial MV	**231**	**14**	**39**

It should be noted though that from year 10 onwards, **a large scale uptake of PV in the domestic and industrial market can be expected.**

Solar Water Heaters (SWHs)/Heat Pumps

The same methodology used to assess the PV market has been applied to SWHs and heat pumps. These results show that within 3 years, solar water heaters and heat pumps are expected to provide a financial payback of under 3 years for the over 2000kWh/month domestic market. By year 5 a SWH/heat pump will be a viable financial proposition for the entire domestic market above 600kWh/ month.

Therefore early adopters (13.5% of the total market) will continue to buy SWHs over the next 3-5 years, after which the early majority phase (34% of the total market) will begin to buy them. In ten years' time a large proportion of the late majority phase market (10% of the total market) is expected to have adopted the technology too. A summary of SWH uptake scenarios is presented below:

		5 year	10 year
Customer sector	**Customers**	**Projected uptake by 2017/18**	**Projected uptake by 2022/23**
Domestic (prepaid meter)	**165 353**	**30217**	**101463**
600-1000	73 867	9972	42473
1000-2000	68 267	9216	39253
2000-3000	13 503	6414	11477
>3000	9 716	4615	8259
Domestic 1 ph (credit meter)	**83 003**	**14549**	**50431**
600-1000	37 028	4999	21291
1000-2000	36 141	4879	20781
2000-3000	6 669	3168	5669
>3000	3 165	1503	2690
Domestic 3 ph (credit meter)	**20 813**	**2910**	**8745**
600-1000	5 536	747	3183
1000-2000	5 076	685	2919
2000-3000	1 309	622	1113
>3000	1 801	855	1531

This projection predicts 48 000 SWHs in the next 5 years, and 160 000 in the next 10 years.

Other interventions

Residential EE

Interventions such as

- Efficient lights (CFLs, LEDs)
- Efficient (low flow) showerheads

are expected to be widely adopted in 10 years' time. This is because currently payback on these items is typically a matter of months (showerhead, CFLs) to a few years (LEDs). It is assumed that 160 000 of the 270 000 domestic customers above 600kWh/month will have adopted these interventions over 10 years

Commercial EE

Interventions such as

- Efficient lighting
- Efficient HVAC

in commercial buildings can reduce electricity consumption easily by 10% with interventions with paybacks of less than 3 years. Therefore a high adoption of these interventions is expected in 10 years' time. A figure of 500 buildings is used, a large proportion of the commercial buildings in the Joburg CBD.

Industrial EE

Interventions such as

- Efficient lighting
- Efficient motors
- Variable speed drives

In industry easily reduce electricity consumption by 5% with paybacks of less than 3 years. As industrial processes vary so greatly, it is difficult to generalise much further than this. It is expected that 25% of industry will implement these interventions over the next 10 years.

14. IMPACT OF RE AND EE ON CITY POWER FINANCES

Using the RE and EE uptake projections presented in the previous section, their impact on City Power finances has been calculated over the next 10 years. The model used to calculate this has been developed by Sustainable Energy Africa with funding from REEEP, and is freely available to any municipality who wishes to use it. It should be noted that while this model has been set up for City Power, it is simple to change the inputs to match the requirements of another municipality. The model is designed to be a thorough analysis of the impact of RE and EE on city finances, and incorporates the following:

i. Weekend and weekday load profiles for winter and summer
ii. RE and EE impact on overall load profile over particular hours of the day for weekdays and weekends over summer and winter
iii. Financial impact of RE and EE based on cost of lost sales to customers and gain from reduced purchases from Eskom. Current City Power customer tariffs and Eskom Megaflex tariffs were used for the calculation
iv. Net metering has been included – any additional PV generation which is fed into the grid is accounted for and purchased at Megaflex rates by City Power. It is then considered to be sold on at City Power tariffs
v. Load shifting due to
    - PV installation
    - Time of Use tariffs

The outputs of the model indicate the impact on overall income of the interventions as

- a figure in Rands,
- a percentage of total revenue and
- a percentage of operational revenue only (Eskom repayments removed).

The total revenue percentage drop is of interest as this will indicate the impact on the ability of City Power to pay a 10% surplus to the City of Joburg rates account. The impact on operational revenue is also of interest, as City Power's ability to manage its network could be affected.

The revenue impact model can be easily edited to simulate many different tariff, growth, technology uptake, load shifting and net metering scenarios. However, a business as usual scenario will be presented here, as the most likely way forward for the distribution utility.

Business as Usual

This scenario assumes that the current City Power tariff structure remains unchanged into the future, with growth in line with Eskom increases and operational cost increases . The key assumptions around this scenario are

- PV, SWH and EE penetration rates linked to uptake scenarios developed for this report
- Purchase of excess PV energy at Megaflex rates (net metering)
- 0% growth in sales up to 2017, 5% growth in sales from 2017 on
- 6% operational growth rate annually for City Power, Eskom electricity increases of 20%, 15%, 15%, 15%, 15% and then 6% for the last 5 years

The results of the Business as Usual (BAU) scenario are presented by sector below in windows of 3, 5 and 10 years from now.

	Year 3		
	Total Revenue	R 21 673 141 713	
	Operational Revenue	R 6 544 578 041	
	Loss	%loss of total revenue	% loss of op revenue
Residential (prepaid)	**-R 26 352 914**	**-0.12%**	**-0.40%**
PV	-R 10 370 765	-0.05%	-0.16%
SWHs	-R 10 352 332	-0.05%	-0.16%
Other ee	-R 5 629 817	-0.03%	-0.09%
Residential (credit)	**-R 11 914 508**	**-0.05%**	**-0.18%**
PV	-R 4 398 922	-0.02%	-0.07%
SWHs	-R 4 820 047	-0.02%	-0.07%
Other ee	-R 2 695 539	-0.01%	-0.04%
Commercial	**-R 17 307 044**	**-0.08%**	**-0.26%**
PV	-R 3 798 276	-0.02%	-0.06%
EE	-R 13 508 769	-0.06%	-0.21%
Industrial	**-R 20 581 405**	**-0.09%**	**-0.31%**
PV	-R 12 952 214	-0.06%	-0.20%
EE	-R 7 629 192	-0.04%	-0.12%
TOTAL	**-R 76 155 872**	**-0.35%**	**-1.16%**

In year 3, a small total revenue loss of .35% can be expected from the projected EE and RE uptake. Nearly 50% of the losses will be realised in the residential market, and approximately 25% each from the commercial and industrial market. This breakdown of revenue loss allocation remains consistent for years 5 and 10.

It should be noted that even though the projected uptake of PV compared to SWHs is significantly lower in the residential market (1 PV system for every 4 SWH systems), the overall financial impact is similar to that of the SWHs. This is due to loss of City Power sales occurring in the middle of the day for PV, when City Power stands to make a surplus on electricity sales, while the SWHs typically result in a loss of sales over peak period, when City Power stands to make very little surplus, or in winter runs at a loss.

	Year 5		
	Total Revenue	R 29 848 706 804	
	Operational Revenue	R 8 063 574 605	
	Loss	%loss of total revenue	% loss of op revenue
Residential (prepaid)	**-R 103 335 105**	**-0.35%**	**-1.28%**
PV	-R 39 310 014	-0.13%	-0.49%
SWHs	-R 41 201 766	-0.14%	-0.51%
Other ee	-R 22 823 325	-0.08%	-0.28%
Residential (credit)	**-R 45 997 926**	**-0.15%**	**-0.57%**
PV	-R 16 654 105	-0.06%	-0.21%
SWHs	-R 18 636 065	-0.06%	-0.23%
Other ee	-R 10 707 756	-0.04%	-0.13%
Commercial	**-R 73 708 116**	**-0.25%**	**-0.91%**
PV	-R 16 181 709	-0.05%	-0.20%
EE	-R 57 526 407	-0.19%	-0.71%
Industrial	**-R 84 447 145**	**-0.28%**	**-1.05%**
PV	-R 52 729 361	-0.18%	-0.65%
EE	-R 31 717 784	-0.11%	-0.39%
TOTAL	**-R 307 488 293**	**-1.03%**	**-3.81%**

In 5 years time, overall revenue losses will have grown to 1.03%, which equates to a 3.81% drop in projected operational income for City Power

	Year 10		
	Total Revenue	R 50 296 805 956	
	Operational Revenue	R 13 587 592 147	
	Loss	%loss of total revenue	% loss of op revenue
Residential (prepaid)	**-R 385 289 009**	**-0.77%**	**-2.84%**
PV	-R 133 716 985	-0.27%	-0.98%
SWHs	-R 164 307 004	-0.33%	-1.21%
Other ee	-R 87 265 020	-0.17%	-0.64%
Residential (credit)	**-R 172 942 392**	**-0.34%**	**-1.27%**
PV	-R 57 573 207	-0.11%	-0.42%
SWHs	-R 74 428 062	-0.15%	-0.55%
Other ee	-R 40 941 123	-0.08%	-0.30%
Commercial	**-R 281 823 107**	**-0.56%**	**-2.07%**
PV	-R 61 870 793	-0.12%	-0.46%
EE	-R 219 952 314	-0.44%	-1.62%
Industrial	**-R 305 886 623**	**-0.61%**	**-2.25%**
PV	-R 201 610 799	-0.40%	-1.48%
EE	-R 104 275 824	-0.21%	-0.77%
TOTAL	**-R 1 145 941 131**	**-2.28%**	**-8.43%**

By year 10, a projected loss of 2.27% of City Power revenue is expected based on the projected uptake figures for EE and RE. This equates to an 8.41% loss in operational income. It should be noted that by year 10 it is expected that PV will be a much more viable proposition for residential and industrial customers, and that a large scale uptake of the technology is likely in the following 5 years. As a result of this revenue losses can be expected to increase rapidly from this point forward.

Sub-scenarios of BAU

While the information presented above is considered a likely future scenario, some sensitivity analysis will be useful to understand variations in some of the assumptions. This short summary shows some of these results:

Sub-scenario 1: No electricity sales growth

Currently City Power is currently experiencing a negative sales growth. This sub scenario assumes that no additional electricity sales above current sales levels are achieved in the next 10 years. The impact of this after 10 years is summarised in the table below.

Year 10		
Total Revenue	R 36 615 207 885	
Operational Revenue	R 9 840 625 575	
Loss	%loss of total revenue	% loss of op revenue
-R 1 135 823 210	-3.10%	-11.54%

The impact of this scenario is that while the losses from RE and EE are the same as BAU, the overall revenue is lower, resulting in a higher percentage loss when compared to the BAU scenario (3.1% compared to 2.28%).

Sub scenario 2: Optimised PV size

This scenario looks at the impact of optimising the PV uptake size to provide maximum energy saving for end users. This scenario does result in a small amount of net generation on weekends, which is considered to be bought at Megaflex tariffs and sold on to other customers.

Year 10		
Total Revenue	R 50 296 805 956	
Operational Revenue	R 13 587 592 147	
Loss	% loss of total revenue	% loss of op revenue
-R 1 413 550 065	-2.81%	-10.40%

This scenario results in an additional 0.53% loss to City Power revenue (2.81% compared to 2.28%)

Sub scenario 3: Doubling PV and SWH uptake

This scenario determines the impact of twice the amount of customers installing PV and SWHs than projected in the BAU scenario

Year 10		
Total Revenue	R 50 296 805 956	
Operational Revenue	R 13 587 592 147	
Loss	%loss of total revenue	% loss of op revenue
-R 1 818 878 158	-3.62%	-13.39%

This scenario shows a substantial additional increase in revenue losses of 1.34% over the BAU scenario. While not likely to occur, this scenario could be an indication of potential losses in 15 years time, when PV systems will be very attractive to residential and industrial customers

Sub scenario 5: Halving PV and SWH uptake

This scenario looks at a more conservative market uptake than that projected in the BAU.

Year 10		
Total Revenue	**R 50 296 805 956**	
Operational Revenue	**R 13 587 592 147**	
Loss	**%loss of total revenue**	**% loss of op revenue**
-R 793 902 003	**-1.58%**	**-5.84%**

This scenario shows a revenue loss reduction of 0.7% when compared to BAU

Sub scenario 6: Implementing a service charge for PV installations

This scenario looks at the impact of City Power imposing a service charge of R5/kWp on any customer who installs a PV system, coupled with a lower energy charge. This is based on the tariff which is currently proposed by the City of Cape Town (88c/kWh). The result shown here was only calculated for residential customers, but can also be applied to commercial and industrial customers. This is merely being presented as an indication of the revenue loss mitigation potential of such a tariff

	Year 10		
	Surplus	**% gain in total revenue**	**% gain in operational revenue**
Residential (prepaid)	R 216 906 947	0.431%	1.596%
Residential (credit)	R 138 136 188	0.275%	1.017%
Total	**R 355 043 135**	**0.706%**	**2.613%**

This shows that implementing a service charge can negate the losses experienced from a PV installation. The setting of the service charge and energy charge figure would need to be fine tuned so as not to overburden the PV customer. These indicative figures merely go to show that the impact of PV can be managed with an alternative tariff approach.

Load Shifting Scenarios

These scenarios look at the impact of residential electricity customers who shift their load from peak times to other times of the day. This is often a conscious decision by the customer, which can be driven by two key factors.

- Optimising PV panel generation for own use. A customer who has installed a PV system would like to make full use of the electricity generated, and not lose it to the grid or lose the excess electricity entirely. Therefore it makes sense for them to shift their electricity usage to the middle of the day when the PV generation is at its highest.
- A residential Time of Use tariff. This will have the effect of motivating money conscious customers to shift their electricity loads from expensive peak periods to less expensive standard and off peak periods

Interestingly, research shows that these conditions will not necessarily cause all customers to shift. Customer shifts due to ToU tariffs can range from as low as 2% and as high as 50%[1]. Research based on load shifting through PV installation shows a typical

[1] Demand Side Response in the domestic sector- a literature review of major trials, Final Report. Undertaken by Frontier Economics and Sustainability First. August 2012

customer load shift of 30%[2]. Based on this research, this analysis will assume a load shift of 30% for both PV and ToU

Load shifting scenario 1: PV users

This scenario looks at the impact of a PV customer load shifting to maximise PV generation benefits.

The table below shows a minimal positive effect on overall revenue loss by year 10. This is due to the small number of PV users who have load shifted. However it is of interest to note that savings are realised from load shifting when PV is being used, and that this is a strategy which should be encouraged.

	BAU		Load shift	
	Rands	% loss	Rands	% loss
Residential	-R 558 231 401	-1.11%	-R 552 753 811	-1.10%

Load shifting scenario 2: ToU tariff causing all customers to load shift

This scenario looks at the impact of a Residential ToU tariff with a 30% load shift of all residential customers. This output shows that considerable losses can be avoided through a residential time of use tariff, and through load shifting.

	BAU	ToU (30% load shift)
SWH	-R 127 100 006	-R 41 807 959
Other ee	-R 67 165 984	-R 30 777 966

15. CONCLUSIONS

1. This report developed a set of projections for RE and EE uptake for City Power's customer base over 10 years.
2. These projections were derived from analysing the financial viability of each RE and EE intervention, and linking this to market uptake research information
3. The projections were inserted into a tool developed by Sustainable Energy Africa which determines their impact on City Power's load profile over typical weekdays and weekends in summer and winter
4. The tool was then used to calculate the impact on revenue of these interventions, taking into account
    a. the time of the loss of sale (daily and seasonal) and linking it to the appropriate megaflex tariff,
    b. the customer tariff
    c. demand savings for City Power
    d. net metering for excess PV generation feeding into the grid
5. A summary of the findings is presented in the two tables below

[2] Solar PV Adoption in the U.S. Residential Sector: Decision-Making & Behavior Change. Varun Rai. Assistant Prof of Public Affairs and Mechanical Engineering, University of Texas at Austin. BECC Conference 2011, Washington D.C. 1 December 2011

BAU					
Summary Table by numbers					
	Customers above 600kWh/month	PV uptake by year 10	SWH uptake by year 10	EE uptake by year 10	Impact on revenue
Residential	269169	44221	160639	160639	-R 558 231 401
Commercial	7335	4148	0	500	-R 281 823 107
Industrial	4005	674	0	2332	-R 305 886 623
					-R 1 145 941 131
Summary Table by percentage					
	Customers above 600kWh/month	PV uptake by year 10	SWH uptake by year 10	EE uptake by year 10	Impact on revenue
Residential	269169	16%	60%	60%	-1.11%
Commercial	7335	57%	0%	7%	-0.56%
Industrial	4005	17%	0%	58%	-0.61%
					-2.28%

The residential sector will be the largest contributor to revenue losses up to year 10 (49%), with industrial (26%) and commercial (25%) making up the balance. It should be noted that residential uptake of PV could increase rapidly as it becomes financially viable from year 10 onwards.

6. The following various sub scenarios were run through the tool to show the impact of
    a. optimised PV installation size projection based on average load profile
    b. doubling the EE and RE projection
    c. halving the EE and RE projection
    d. no electricity sales growth

    Year 10 results are summarised and compared against BAU in the table below:

	Impact on revenue		Difference against BAU	
Sub-scenarios	**in Rands**	**as percentage**	**in Rands**	**as percentage**
BAU	-R 1 145 941 131	-2.28%	R 0	0.00%
Optimised PV Size	-R 1 413 550 065	-2.81%	-R 267 608 934	-0.53%
Double projected uptake	-R 1 818 878 158	-3.62%	-R 672 937 027	-1.34%
Half projected uptake	-R 799 187 706	-1.59%	R 346 753 425	0.69%
No electricity sales growth	-R 1 145 941 131	-3.10%	R 0	-0.82%

Key findings from this exercise are

a. A doubling of the projected RE and EE uptake will result in a 1.34% increase in revenue losses
b. A halving of the uptake will result in a 0.69% improvement in overall revenue losses
c. No electricity sales growth will result in a larger impact on revenue percentage, as overall revenue is less, while losses are the same as BAU
d. Optimising PV size shows the upper limit of PV generation for the projected uptake.

7. The implementation of a daily service charge for PV systems is a potential method for loss recovery. This method has been proposed by the City of Cape Town.
8. Load shifting for PV users is still beneficial to City Power, even though losses are incurred by the PV unit itself.
9. A residential ToU tariff will also benefit City Power by reducing losses from EE and RE interventions.

In summary then, it is reasonable to expect that EE and RE interventions will result in an increasing revenue drop year by year, culminating in a drop of 2.8% for City Power in 10 years time. These losses could be absorbed internally by City Power, or be passed on to the City of Joburg – ultimately a management decision. Either way, the amount is fairly substantial, and will have an impact on service delivery into the future.

Two potential strategies to make up for some of the losses are to implement a daily service charge for grid connected PV systems, or to implement a residential time of use tariff.

This case study shows that City Power, and indeed most municipalities in South Africa, will need to plan for the impact of EE and RE into the future, and develop strategies on how best to manage it.

It should be noted that the tool developed to calculate the impact of RE and EE on municipal finances is freely available from Sustainable Energy Africa. Please contact us by email at andrew@sustainable.org.za or at 021-7023622.