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AMEU

64th AMEU Convention

5 to 8 October 2014

"Supporting SA infrastructure and service delivery objectives"

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Royal HaskoningDHV

Enhancing Society Together

Special AMEU Convention Proceedings edition

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AMEU Proceedings

2014

Mogale City substation upgrading and construction programme

Information from Royal HaskoningDHV

Following on from the successful completion of the Krugersdorp North substation upgrade in June 2012, Royal HaskoningDHV has been awarded the contract by Mogale City local municipality (Krugersdorp) for a major upgrade of the Condale substation with a value of close to R140-million. The contract, which was awarded in the latter part of 2012, is on track and due for completion in early 2015.

The existing Condale substation, built over 60 years ago, was in need of an upgrade to accommodate the growing population of Mogale City and to ensure stable electricity supply capacity for the expanding community. The upgrade was also necessary to accommodate the proposed new Eskom infeed transformer. The existing equipment, with a fault current rating of 15 kA, is being upgraded to 25 kA. New and improved control and protection systems incorporating the latest technology are also being installed. Condale is the only main infeed substation for the whole of Mogale City.

Thys van Rooyen, Royal HaskoningDHV's design and project manager, says that one of the challenges the Condale project presents is that it is a live yard, which means that the whole substation is being rebuilt under live yard conditions. This makes it dangerous as the substation is currently operating at full capacity, and so safety is of paramount importance.

The high electricity demand in the winter months had to be taken into consideration when planning the switchover to the new system, and back-ups need to be in place. In addition recent mine operations and recycling in close proximity to the substation has caused many problems. The acidity of the mine dust damages equipment and galvanising on steelwork. New maintenance procedures have been implemented to clean and maintain heavy duty galvanising.

The project to upgrade the 33/6,6 kV Condale substation includes the supply, delivery, off-loading, installation, erection, commissioning and handing-over in a proper working condition of all materials and equipment including all related cable, steel, civil and other works required to make the substation fully functional. This includes the western and eastern extensions of the substation; upgrading of the existing yard and 33 kV switch room; a new 10 MVA 33/6,6 kV transformer bay; and the new 6,6 kV switch room including all equipment and switchover of all 6,6 kV cables.

The western extension of the substation includes the extension of the 33 kV busbars with three new bays (3200 A, 25 kA) which comprises two new 33 kV line feeder bays and one new bus-coupler bay. The eastern extension of the substation includes extension of the 33 kV busbars with ten new bays (3200 A, 25 kA) comprising seven new 33 kV line feeder bays; one new Eskom incomer bay and the relocation of the existing incomer; one new bus-coupler bay; and one new bus-section bay.

The upgrading of the existing yard and 33 kV switch room comprises the modification and upgrade of 25 existing bays; the upgrade of the existing tubular busbar system to 3200 A, 25 kA; the upgrade of control and protection panels for the existing bays; the control and protection panels for new 33 kV bays; new self-supporting transmission poles to relocate Spruit 1 and 2 feeders; gantries for new Boltonia 1 and 2 and KDN 2, 3 and 4 overhead lines; new dual battery and dual charger with changeover systems; and new AC and DC distribution panels. In addition to this is the provision of a new 10 MVA 33/6,6 kV transformer bay for a new transformer.

Equipping the new 6,6 kV switch room and the switchover of all the 6,6 kV cables involves the demolition of the old Teddie Niell outdoor switchyard and the construction of a new 6,6 kV switch room. It includes a new 110 V DC battery charger and batteries; a new 240/415 V chop-over supply in the new substation building; the replacement of all of the medium voltage, multicore and low voltage cabling; the extension of the existing earthing and earth mat; new earthing and a new earth mat for the 6,6 kV substation; two new ripple control units for the 10 MVA transformers and the relocation of the existing two units for demand side management (DSM); two new capacitor banks and the relocation of the existing two units also for DSM; swing over of all existing 6,6 kV feeders to the new substation; relocation of the feeders from the old Teddy Niell 6,6 kV substation to the new substation; and the dismantling of the old 6,6 kV switchgear in the existing Condale 6,6 kV substation.

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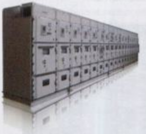
Fig. 1: Condale substation upgrade.



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Welcome address by the AMEU president

It gives me great pleasure to welcome you to Gallagher Estate for this 64th convention of the AMEU and to wish you a most productive and worthwhile conference. You will be aware that our incoming president is a "Jo'burg man" and that the City of Johannesburg, in conjunction with City Power, is hosting our meetings. Allow me to express sincere appreciation to the city for its hospitality. I record this with deep appreciation and sincerity on behalf of all the delegates, and also the AMEU and the executive council.

I also record thanks to our affiliate members and their committee not only for their greatly appreciated sponsorship and support, but also for the tremendous amount of work that has gone on behind the scenes and significantly contributes to making this conference possible and worthwhile.

Special thanks go to the AMEU Secretariat and the organising committee which have worked tirelessly to ensure that no detail has been overlooked to make this a memorable event. This includes not just the practical details that ensure facilities are all in place, but also the details of the program and the papers that ultimately make the gathering a valuable learning experience.

It would be remiss of me not to make mention of the work put into the program for partners of the delegates. I am sure that this very important part of our meeting is appreciated by all who participate in the activities, and on their behalf I record appreciation to the organisers and the sponsors who have made it all possible.

To each and everyone, I say "Thank you" for what you have contributed to making this a memorable convention and trust that you will benefit from the information taken from the various presentations, from the technical displays in the exhibition, and from the networking with colleagues, and that when you finally return to your offices you will be able to apply a great deal of the information to the benefit of your customers.

Hannes Roos, AMEU president

Hannes Roos, AMEU president

Incoming president's address at the AMEU Convention 2014

I am deeply honoured and humbled to be given the opportunity to head the Association of Municipal Electricity Utilities of Southern Africa (AMEU). I wish to thank my colleagues, industry associates and stakeholders for expressing their confidence in me by electing me to this important position.

I assure you that I will carry out these duties with honour and diligence.

On behalf of the AMEU members, I would also like to take this opportunity to thank the outgoing AMEU President, Mr. Hannes Roos for his judicious and astute leadership. Mr. Roos, the AMEU grew in stature under your leadership to become a force to be reckoned with. As the incoming president, I have big shoes to fill and I shall certainly defer to you for counsel and advice.

Building on the impeccable work that has been done by my predecessors, I plan to hit the ground running and tackle head on a number of substantive issues.

One of the most important initiatives that I wish to drive in my tenure is transformation. The industry is one of the least transformed industries in the country. Women still play a miniscule role in this sector and I believe that this needs to change. My objective is make women, particularly African women, a critical mass in the electricity supply industry.

Driving transformation and fast-tracking women's advancement in the sector will not be easy. It requires political will and a firm undertaking to change the composition of this sector. Transformation of the sector should not be about ticking boxes, but about achieving meaningful transformation by identifying the right candidates with the right skills set, and providing coaching and mentoring opportunities to enable them to add value to the AMEU.

I also plan to strengthen and revisit some of the agreements the AMEU has entered into with a number of industry stakeholders such as the South African Local Government Association, the Department of Energy, NERSA, SASGI, LGSETA, SACCI and EIUG. It is important that we revisit some of these agreements, review progress made and fast-track delivery on what remains outstanding. Some of the pertinent issues which come to mind are industry restructuring, tariff harmonisation, service delivery agreements, security of supply, funding of the infrastructure

Sicelo Xulu, AMEU incoming president.

backlog, renewable energy and smart grid initiatives, just to mention a few.

As the AMEU we need to redouble our efforts into using metros as pillars that drive the AMEU agenda. Metropolitan municipalities have the capacity and the budget to drive the AMEU mandate of promoting quality of service and management excellence amongst its members in the field of electricity supply through communication between members and the technical, economic and political environment, in the interest of national energy efficiency.

In line with its mandate, the AMEU needs to provide support to municipalities, especially smaller and rural municipalities, and capacitate them to enable them to achieve their objectives. The provision of this support will go a long way towards helping them to deliver service efficiently and to deliver on their mandates.

We should also be mindful that municipalities derive approximately 40% of their revenues from electricity collection. It is therefore crucial that the AMEU assists capacitating these entities with the tools to help them to meet their objectives in order to ensure their viability and long term sustainability.

The AMEU needs to become more relevant to municipalities, particularly those that are on the periphery. We will need to play a more active role and become the voice of these municipalities: through lobbying on their behalf and playing an advisory role.

It is important that we increase AMEU membership, particularly among rural and small municipalities. In order for this to materialise, we need to win the hearts and minds of potential members by demonstrating the tangible benefits of being members of the AMEU.

Municipalities also need to come to the party and play their role as well. They need to root out corruption and maladministration in their midst. They should demonstrate a firm commitment to good corporate governance and apply zero tolerance to corruption without fear or favour. They should be seen to be acting decisively and firmly against corruption and maladministration.

Municipalities need to deliver on their mandate and become diligent servants of the constituency they serve.

During my tenure, I will be focusing on a number of areas, including speeding up the adoption of alternative sources of energy. We need to fast-track the adoption of renewable energy sources to alleviate the pressure on the grid, and lessen our carbon footprint.

We also need to build on the concept of smart cities and help big metros to achieve their objectives of becoming smart cities. I know that concerted efforts have already been put in place to bring Johannesburg closer to achieving smart city status.

Cable theft continues to be a niggling challenge which needs to be dealt with decisively. We need to keep up the momentum and tighten the screws further on unscrupulous people throughout the value chain, be they our employees or unscrupulous scrap yard dealers. We have to fortify and strengthen the multi-stakeholder engagement and ensure that the work we do with law enforcement agencies and our communities bears fruit.

The announcement that the first phase of the much-awaited Medupi power plant will go live on 24 December 2014 is great news for all of us – we couldn't have asked for a better Christmas present. Medupi will go a long way towards providing the grid with much-needed capacity.

I am looking forward to working with all of you, and I remain confident that together we can propel the AMEU to new heights.

Sicelo Xulu, incoming president

Keynote address at the AMEU Convention 2014

This is a summary of the keynote address presented by Dr. Wolsey Barnard, the deputy director-general of energy programmes at the Department of Energy (DoE).

The Department of Energy's Dr. Wolsey Barnard, says South African municipalities need to improve electricity service delivery and clear backlogs so that more residents can have access to electricity.

Speaking at the opening of the 64th annual AMEU convention held at Gallagher Estate, in Midrand on 5 to 8 October 2014, Dr. Barnard, the deputy director general of energy programmes and projects, said that although the country has made marvellous strides in achieving democracy, service delivery has not kept up with its needs. The country, he said, is severely challenged with regard to its electricity supply due to a lack of human capacity, financial capacity, and generation capacity. The importance of energy as a stimulus for economic growth, he said, cannot be overstated.

Power generation

Dr. Barnard said that because South Africa's generation system is very tight, the country's previous administration had put some strategies in place to make sure that the country would have sufficient electricity to support economic growth. Although some of these projects are running behind schedule, others are already generating electricity. About three-and-a-half years ago the government's renewable energy independent power producers programme (REIPPP) was launched, and 16 of the original projects are currently exporting 900 MW onto the grid.

Earlier this year, in the interests of ensuring that South Africa has a secure supply of electricity, Tina Joemat-Pettersson, the minister of energy, and the equivalent minister from the DRC signed an agreement to make sure that the development of the Inga hydroelectric project goes ahead as South Africa needs to source 2500 MW from phase one of this project.

According to Dr. Barnard, the future of South Africa's energy resource planning, in terms of generation, includes gas, renewable energy sources, imported hydroelectricity, coal and nuclear. These will all play a major role in coming years to make sure that the country will have an adequate power supply. Regarding nuclear energy, he said that the DoE is still investigating different nuclear technologies offered by various countries and entities. He said that the procurement process, in terms of nuclear, is not just to supply electricity but to supply other technologies too. The DoE also intends to procure 800 MW from cogeneration plants, and 2400 MW from coal-fired power stations. Peaker stations, which will be completed in 2015/2016, will add another 1000 MW.

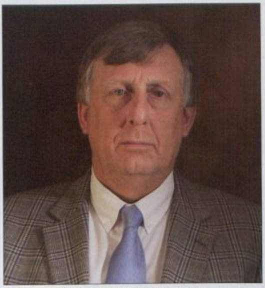
Electricity distribution

Maintenance backlog

Dr. Barnard said that the country needs to address the poor quality of supply as well as its slow service delivery. In line with this, he said that the DoE will establish stakeholder engagements regarding electricity supply where targets can be set, and industry can be assured of receiving high quality services. He also addressed the problem of infrastructure maintenance, refurbishment and upgrading backlogs which need to be resolved. The DoE has recently undertaken studies which show that these backlogs currently stand at R68-billion (up from R27-billion).

Municipal electricity debt

Dr. Barnard admitted that dealing with Eskom's sustainability as an entity is a big issue, and said that one of the main contributors to Eskom's financial problems is the matter of unpaid debts by certain municipalities. He said that in some municipalities revenue management systems aren't always managed as efficiently as they are supposed to be. This is harming the industry, he said, as figures that he had seen are concerning and may "pull the plug" on the country's whole electrical supply industry (ESI) value chain.



Dr. Wolsey Barnard, Department of Energy

Illegal connections

Dr. Barnard said that the matter of illegal connections is very serious and has to be addressed effectively, even though it is a problem which is not easy to solve. He described a situation where a householder stole power from a cellphone tower's emergency power supply by passing a cable under a tarred road between the house and cell phone tower.

Energy efficiency

Energy efficiency measures need to be considered very seriously by local authorities, he added. Although this may require the use of smart grid upgrades and other technology improvements, energy efficiency helps to reduce the demand for power which is better and cheaper than generating more power to meet demand. These serious concerns around the distribution of electricity, he said, are so important that if not addressed the country will end up having a greater generation capacity than it has means to distribute.

Electrification

Regarding access to electricity, Dr. Barnard reported that, as at the end of the last financial year, over 6-million connections had been made, with close to 307 000 grid connections being established last year alone. There are also over 80 000 residents benefiting from off-grid (mostly PV) electrification.

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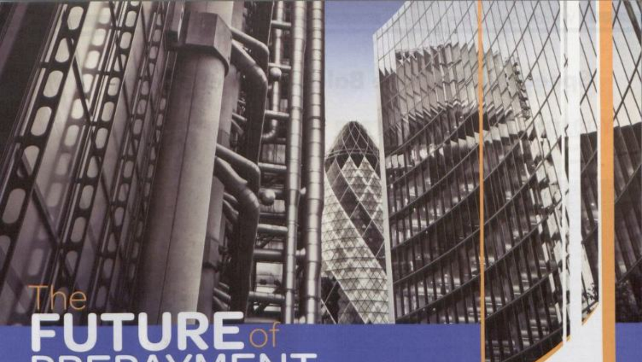

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CONLOG
Solutions for utilities

Speech by Phindile Baleni, CEO of NERSA

It is my pleasure and honour to be given the opportunity to say a few words on behalf of the National Energy Regulator at the 64th convention of the AMEU. Congratulations on this stimulating convention held under the theme: "Moving towards Southern Africa's electricity networks of the future".

Ladies and gentlemen, it is true that the electricity industry is changing and ten years from today we might be looking at a very different industry. Looking at the main topics of the conference, the changes that are being spoken about have the possibility of creating hundreds and perhaps even thousands of new jobs. However, the question must be asked whether it will result in new jobs or new vacancies? The jobs that are to be created are for skilled people, but where will they come from? There are a few concerns that this changing industry needs to address.

The first challenge is the lack of skills in the industry. As the National Energy Regulator, we would like to appeal to the sector in general and large metros in particular, to set up training programmes to train people for the industry. This should not just be for the large metros' own needs, but to create a pool that can also meet the needs of the smaller municipalities. We also appeal to organisations like the AMEU, which has an overarching interest in the industry as a whole, to take up the cause of training and apprenticeships to provide for the industry in the future.

The other main challenge that is of concern to the Energy Regulator regards the use of smart meters. These concerns include financial control, security and the customer experience of these systems.

Financial control is really a problem of stock control, to use a common-place analogy. This is well known and understood by the supermarket manager, but these skills and processes have not been applied to the electricity industry. There needs to be a shift in the way that we think about the product that is sold and how we sell it. It may sound obvious that all the electricity provided to customers must be paid for, however, the moment that you separate the stock delivery system from the payment system, extra measures need to be put in place. These are required to ensure proper stock control. This separation is what is happening when we move to a prepayment system, which seems to be implicit with the move to smart metering. This separates the point of sale from the point of delivery.

To address this challenge, there are three reconciliations required:

- The financial accounting of the tokens sold to the money received.
- The physical reconciliation and tracking of the electrical energy bought and delivered.
- The reconciliation of electrical energy delivered to the tokens sold.

Most municipalities will do the first one well, the second one not very well, and the third one not at all. One of the key reasons for this situation is that the second and third reconciliations require a lot of extra metering points. This is so that there can be appropriate accounting of the energy delivered (stock control) and there are costs associated with this. It also requires specific checks and balances to identify areas of loss, which is a skilled job. The third reconciliation also requires that the meters should be able to be interrogated to determine the unused amount of tokens loaded.

Ladies and gentlemen, these three steps need to be reconciled with each other. If not, there is the opportunity for stock loss; and stock loss, if unchecked, closes businesses. Many supermarkets have closed due a lack of stock control. The challenge is that municipalities may not go out of business in the same way – they will request a higher price increase. The problem of uncontrolled energy losses cannot continuously be addressed through higher-than-guideline tariff increases.

Phindile Baleni, CEO of NERSA

The challenge is that the industry does not view energy and energy sales in the same way that a retailer or supermarket views their stock movements. I suggest that we align our approach to the changing energy industry with this approach.

In this regard, energy sales or revenue protection departments need to adopt many new procedures and processes. It is no longer sufficient to just reconcile the financial side and sales of tokens – there needs to be a full reconciliation. It is critical to note that the amounts of money involved are significant, thus there is tremendous incentive and opportunity for the unscrupulous to defraud the municipalities. This means that there must also be tremendous incentives of financial reward for the municipalities to adopt the right procedures.

Security issues also arise. It seems from media reports that almost any network can be hacked by determined and technically competent people. This means that the municipalities need to have plans and procedures in place to handle this eventuality.

In the USA, the possibility of hacking has driven much of the resistance to smart meters, although they argue their case on the basis of concerns over privacy, which also needs to be taken into account. In this regard the US Department of Energy has just released a draft voluntary code of conduct for data privacy and the smart grid which could form a starting point of discussion for the AMEU to draft one specifically for South African municipalities.

The other hot topic is that of rooftop solar installations, which has many implications for the industry. Some are foreseen, but many are as yet unseen. We cannot adopt the idealistic view that roof top solar panels is the answer to all our energy problems. We need to take a much more pragmatic and realistic approach, which while seeing the benefits, also sees the disadvantages. We then need to try to extract the benefits while reducing the disadvantages. In this regard, the National Energy Regulator will be publishing a consultation paper in

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2015, seeking both to obtain public comments and to raise awareness of all the issues to enable adequate engagement.

Tariff-related issues remain a challenge. NERSA is requesting the municipalities to do cost of supply studies, which need to be done every five years according to the Electricity Pricing Policy. NERSA is also working on a framework to assist the municipalities and provide more clarity on what is required.

Ladies and gentlemen, the industry seems to be hampered by both a shortage of skills and good information upon which to base decisions. As we all know, good decisions are not possible without good information. These issues are critical because the municipal tariffs are in many cases relatively high. This should be a concern for the municipalities because businesses cannot thrive if the tariffs are intolerably high. The revenue that municipalities will lose by keeping their tariffs lower will be recovered in the long run by having thriving businesses in their area.

It was interesting for NERSA to discover a case of two similar companies in different towns which for purposes of discretion I will not mention by name, where one was thriving and exporting product, ,and the other struggling. The thriving business was paying 13% less for its electricity (based on the same load profile), which seems to indicate a link between lower tariffs and economic success. It is something to think about.

I would like to conclude my remarks by suggesting that we accept a collective responsibility for growing the economy of South Africa, and execute our mandates and responsibilities in a way which will promote economic growth and the creation of quality job opportunities.

Congratulations to the incoming president, Mr. Sicelo Xulu, and we are looking forward to a continued strong relationship with AMEU.

I wish you fruitful deliberations as you share your insights on these issues, cable theft and others that challenge operators in 2014.

Phindile Baleni, CEO of NERSA

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Funding

Dr. Barnard said that funds have been provided for the refurbishment and upgrading of equipment so that new connections can be made to supply additional households with electricity. However, he said that too much of this money remains unspent. As a result, the DoE finds itself in a very difficult situation at national level when it tries to argue for more funding when there is still so much unused. He reported that in the 2011/2012 financial year, 30% of the approved projects were uncompleted; in the 2012/2013 financial year, 43% of the projects were uncompleted; and in the 2013/14 financial year, 40% were uncompleted.

Solar water heaters

Dr. Barnard ended off by saying that many of the solar water heating systems which have been installed countrywide were imported, not of a high quality and poorly installed. In response to this, the DoE has decided to initiate a local procurement programme where only local products will be used. The specifications will call for 70% local content for both the tank and the collector, with the intention being to roll out a full scale South African manufactured product, installed by locally trained and certified individuals. More details will be made available regarding the qualification and training of these installers and SMEs in due course.

Dr. Wolsey Barnard, Department of Energy

Moferefere Tshabalala, president elect.

Sicelo Xulu was inaugurated as AMEU president by outgoing president Hannes Roos.

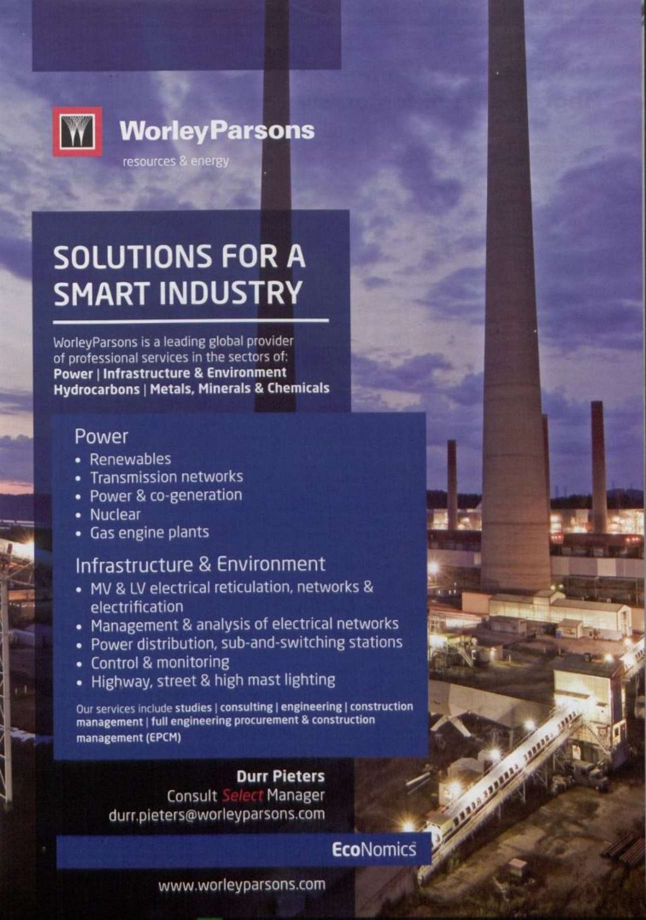
NERSA CEO Phindile Baleni.

Dr. Willem du Toit was awarded the AMEU Best Paper award.

Kevin Kotzen was awarded the Cigré Best Paper award.

Joe Rennie and Pierre van den Heever received honourary membership certificates from Hannes Roos.

Bishop Malusi Mpumlwana, Trevor Fowler, Sandile Maphumulo, Dr. Wolsey Barnard, Hannes Roos, Andries Nel, Matshidiso Mfikoe, Jean Venter and Sicelo Xulu.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Promoting telecomms and ICT – essential ingredients of tomorrow's network

by Peter Moray, Utilities Telecoms Council, USA

This paper sets out the case for establishing the Africa Utility Telecoms Council (AUTC) as an international division of the Utilities Telecoms Council (UTC) based in Washington DC, USA.

At present, there is no body or organisation within the utility sectors which addresses what is rapidly becoming a critical element in the energy and utility value chain. UTC is a global trade association dedicated to creating a favourable business, regulatory, and technological environment for companies that own, manage, or provide critical telecommunications systems in support of their core business. UTC has already established international divisions in America Latina, Canada and in Europe. UTC and the international divisions represent electric, gas, and water utilities; natural gas pipelines; critical infrastructure companies and other industry stakeholders.

Business drivers in the energy and utility sectors

Energy and utility companies around the world are examining the traditional energy delivery cycle of production, transmission and distribution and are under pressure to reduce reliance on fossil fuels, increase the use of renewable sources of energy, improve demand management, ensure adequate supplies and minimise costs. Across the wider Africa region the need to rollout electrification dwarfs these other concerns but nonetheless existing energy businesses are being asked to address a range of business drivers by their governments, regulators and customers.

Typical of these are:

- Greater efficiency throughout the energy life cycle, production, transmission, distribution and in the way energy is used in businesses and in homes.
- Emphasis on reducing fossil fuels and moving to renewable generation.
- Introducing local generation and demand side management.
- Introduce load balancing in distribution networks.
- Improvements in quality of services, reduced outage times.
- Improvements in energy network utilisation and management.
- Implement smart metering solutions to improve customer billing, protect revenue and improve returns on investment in energy.
- Use of microgrids either as standalone units or running interconnected with primary grids.

In addition, utilities are being encouraged to develop international connectivity in transmission system power pools and in developing areas to use the telecoms' assets of energy infrastructure to support the development of telecommunications services. Such business opportunities exist in transmission networks to support a wholesale telecoms market and in distribution networks where there is the potential to also support the rollout of broadband to businesses and homes.

While the initiatives identified above tend to be focused on the energy infrastructure and can largely be considered as operational, all utilities are large enterprise businesses and so need to implement and maintain large IT networks and the range of enterprise services needed for the business to function properly.

Many of these initiatives will rely on enhanced intelligence in all voltage layers of existing energy networks and extended use of many different technologies.

Telecommunications and ICT

The traditional approach to the provision of telecoms services in almost all utilities has been to consider two service elements. Firstly, there are the corporate telecommunications services which support all of the enterprise functions, providing communications between offices, supporting customer contact centres etc. Secondly there are the telecommunications which are essential for the control, monitoring and management of the energy networks, the operational telecommunications. These are critical to the safe operation of the energy network, have diverse routing, backup power and are specified with very high performance characteristics essential to maintaining safe, reliable high voltage networks. Most companies provide these telecoms services in support of their HV and EHV networks.

The majority of distribution businesses, whether in the developed or the developing regions, do not, today, monitor, manage or control their medium voltage (MV) and low voltage (LV) distribution networks. Where the number of MV and LV assets is very high, they are distributed across relatively large geographical locations and to date, there has been no reason to consider the high level of investment required.

The evolution from dumb energy networks to smart energy networks is turning this principal on its head. The key enabler to all of the initiatives being implemented for smart energy networks is a reliance on an increasing level of intelligence, not only in the higher voltage levels, but also in the tens of thousands of assets in medium voltage and the millions of assets in low voltage networks.

Transmission and distribution companies across the world are being challenged to consider how they will provide communications systems and services to support the complex applications which are required to deliver on the challenges facing the energy sector.

There is no shortage of technology. Fixed networks have choices in optical fibre, microwave point to point and point to multi-point networks. Wireless technologies include traditional private radio in many forms, TETRA, P25, DMR and then there are new technologies such as mesh radio and, most recently, LTE, all capable of operating in licensed and unlicensed spectrum bands.

The decision to build, own and operate utility telecommunications is no longer a forgone conclusion. Utility companies use public mobile phone services, there are competing providers and prices are driven down by competition. Some utilities look to specialist service provision companies to manage their operational telecommunications and some have fully outsourced their telecoms provision.

Telcom companies are abandoning their traditional digital networks and moving to packet based solutions, so-called next generation networks (NGNs). Public NGN networks cannot support the special characteristics demanded by the range of tele-protection services and so new investment is required to replace telcom leased lines.

The utility TDM/PDH/SDH telecommunication systems used today are being phased out by vendors and suppliers as they are also now promoting IP/packet based platforms which can deliver greater efficiencies by using a single platform where shared services for corporate telecoms and operational telecoms can exist on the same solution. The move to packet solutions raises the issue of cyber security: what are risks, how are they defined and then mitigated? When asked in a recent board of directors meeting of European UTC to name their single greatest concern, telecom directors and managers pointed to cyber security.

Utilities Telecom Council and the Global Advisory Council

For those operational directors, managers and engineers across the Africa region challenged with finding the most appropriate telecoms solutions for transmission and distribution businesses, UTC's utility members around the world provide a wealth of knowledge and experience willingly shared in peer to peer relationships.

Formed in 1948, UTC has, over twenty years, evolved into a dynamic organisation that represents electric, gas, and water utilities; natural gas pipelines; critical infrastructure companies and other industry stakeholders.

From its headquarters in downtown Washington DC, UTC provides information, products and services that help members:

- Manage their telecommunications and information technology more effectively and efficiently.
- Voice their concerns to legislators and regulators.
- Identify and capitalise on opportunities linked to deregulation worldwide.
- Network with other telecom and IT professionals.

Within the USA, UTC is also an authorised certified frequency coordinator for the Private Land Mobile Radio Services below 512 MHz and 800 – 900 MHz frequencies. UTC is also the sole frequency coordinator authorised to coordinate channels previously allocated exclusively to the Power Radio Service. In addition, UTC maintains the national Power Line Carrier (PLC) database for the coordination of PLC use with licensed government radio services in the 10 – 490 kHz band.

Serving the industry for over 60 years has given us a unique position as a market leader for utility telecommunication advocacy and education.

To support and enhance the sharing of knowledge and to promote education and development of skills in utility telecommunications, UTC, formed the Global Advisory Council in February 2014. The council consists of all the leaders of the international regions, USA, Canada, Europe and Latin America. The council is an advisory body concentrating on adding value to all members of UTC around the world. In practice, such a process was already in place prior to forming the council, albeit operating informally and it was agreed that additional benefits would be gained by creating a formal structure to approve a programme of work, monitor activities and ensure the delivery of maximum benefit. The first formal meeting of the GAC will take place in Monaco in conjunction with the European UTC annual conference. The first chairman of the GAC will be Miguel Angel Sanchez Fornie, director of telecommunications of Iberdrola, Spain.

The leadership team of a future Africa UTC will sit at the Global Advisory Council and have equal rights and access to all the GAC activities.

The GAC has prioritised four initial areas of activity into an international programme of work. Each of the four activities was already work in progress and being managed within different international regions but without any central coordination from within UTC. A director of global programmes now coordinates effort from across the international regions.

The four activities for international collaboration are:

- *Packet/IP networks working group:* It is clear that there are UTC utility members who have made the decision to transition their telecom networks to a packet/IP based solution. The vast majority have not yet made such a decision and the UTC Packet/IP Working Group (WG) will be a peer to peer utility WG providing education and knowledge sharing on the issues, pitfalls and lessons learned in designing, procuring and implementing packet based services. The first activity of this group will be a webinar illustrating the experiences of three member utilities in Europe and North America.

- *Wireless spectrum for future smartgrids:* Many of the applications to be implemented in support of future smartgrids will rely on the medium of wireless in order to gather data and instigate network control functions. European utilities have been promoting the need for additional wireless spectrum for smartgrids with the central regulatory body in the European Commission. A perceived weakness in the arguments has been that utilities have never been formally recognised in the World Administrative Conference (WARC) as users of spectrum in a similar way to the aeronautical industry or the maritime sector. UTC will coordinate the arguments which need to be made in different international jurisdictions to ensure utilities are recognised as users of wireless services in the WRC meetings scheduled for 2015 and 2018. This work is now progressing with UTC in USA, UTC Latin America and UTC Canada. Support is also being provided to EUTC utility members in Africa.
- *Cyber security:* Cyber security is rapidly becoming the number one issue for the world's energy and utility companies. Government bodies in the USA and in Europe already cooperate and share knowledge on all aspects of cyber security. UTC believes a utility based knowledge sharing forum discussing and addressing the specific issues faced by this mission critical sector will benefit all members. The work of the UTC Cyber Security Committee will be promoted to all UTC utility members and new alliances with European experts are under discussion within EUTC to consider collaboration on educational programs.
- *Utility telcom network KPIs:* UTC has developed a draft document setting out the key performance indicators which could be used to determine the overall performance of utility telecom networks. This initiative was prompted by a request from a South African utility member who provided an initial draft document. An international review process with participation from all international regions has produced a final document which will form the basis of a data gathering exercise in the fall of 2014. The data provided by a selection of utility member companies from all regions will be analysed and benchmarked to show the range of performance of utility networks, identifying best in class and how such performance can be achieved. Data gathering will commence shortly and confidentiality of all data provided will be assured.

The formation of Africa UTC

Six years ago, UTC/EUTC received an application for membership from Eskom Research and Innovation and it was decided they would become charter members of European UTC. Two years later, Ghana Grid became the second member of EUTC from the Africa region. In support of both of these companies, UTC/EUTC held utility telecom conferences in 2012 and again in 2013. The feedback from these events, supplemented by research in South Africa and by very positive reactions from industry bodies including the AMEU, PIESA, SAIEE, AFSEC, SAPP, WAPP, FTTH Africa and SANEDI/SASGI, has made UTC believe the time is right to launch Africa UTC using a similar business model to European UTC.

European UTC was formalised in October 2004 with five utility members. The budget allowed for the appointment of a European director to develop and promote the activities of EUTC taking direction from an European board of directors. EUTC now has 23 charter members and seven associate members. The board of directors agrees on the activities and programmes that the association will provide for all members and the European director is charged with delivery, often through liaisons with other utility associations, energy and telecom regulators, and the bodies within the European Commission.

All back office functions are provided by a contracted association management company which is responsible for finance, membership organisation, the annual conference and appropriate project management of additional technical and business related projects. Management of an annual budget is the responsibility of the director and the association management team. The budget is set by the European board of directors which includes the CEO of UTC in USA. EUTC is an operating division of UTC.

Technical support and resources from member companies are encouraged to participate in projects, some of which may be funded by sponsors and/or the European Commission.

It is proposed that Africa UTC will use the same business model and will have a board of directors drawn from utility members across the continent.

Africa Utility Telecoms Summit and Africa UTC

The launch event for Africa UTC will be the Africa Utility Telecoms Summit to be held in Sandton, South Africa, on 17 to 19 November. The summit is structured to promote debate on a range of telecom technical and business issues as they affect utility companies in the region. The content of these sessions has come from direct involvement of African energy companies and the municipal utilities of South Africa.

At the same time, two sessions in the summit have been reserved for direct discussions on forming Africa UTC and these sessions will explain the proposed structure, organisation, governance and funding of Africa UTC. The benefits of membership will be explained together with a proposal for activities and deliverables for the short term. Once established, the AUTC board of directors will set the direction and programme of activities for the association in accordance with the needs of the membership.

Conclusion

The energy and utility sectors around the world cannot ignore the demands for greater efficiencies and the challenges that will be placed on their businesses over the coming decade with the introduction of smartgrids. The key enabler to smart energy is telecommunications and information communications technologies. There is no single solution, what is best for any particular company is dependent on a number of local conditions, government and regulatory environment, appetite for investment, securing return on investment, technology, availability of spectrum and the level of competition in the telecoms market.

African utilities have an opportunity to come together as part of the wider UTC community to share in a global forum of utility telecommunications while addressing local issues. African utilities can learn from other utility companies and can share their innovative ideas and solutions with others in UTC. Together, the UTC international regions can influence the vendor communities to create and deliver suitable products and services that meet the exacting requirements of the energy infrastructure. All utilities will face the same challenges, the timescales for implementation may be different but we are all aiming to deliver reliable energy at an economical cost and under the best environmental conditions for our particular region.

Africa UTC is the opportunity for all those involved in delivering mission critical services to come together with the common aim of driving better value and improvement in quality of services for businesses through the use of new telecommunications technologies and services.

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Landis+Gyr E460

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Open smart prepayment meter solution

Landis+Gyr's E460 meter solution is the answer to advanced smart prepayment metering needs.

The new generation E460 smart prepayment meter solution is rich in functionality and offers maximum flexibility.

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Open international standards

- G3 – PLC
- STS prepayment standard (IEC62055-41/51)
- Interoperable IDIS standard
- DLMS / COSEM communication protocols

Features

Open industry standard, G3-PLC OFDM technology for bi-directional communications between the E460 meter, the P160 Customer Interface Unit and the Data Concentrator.

Split metering solution, which typically consists of two parts; the E460 meter and the P160 Customer Interface Unit.

Communication between the meter and the Customer Interface Unit is by means of G3-PLC using existing household wiring; no additional communication wires are required.

The P160 Customer Interface Unit is typically installed in the consumer's home wherever there is a suitable electrical socket outlet available.

Real Time Clock and Time of Use - enabled in the on-line smart prepay and post-pay configuration modes.

Supports the latest STS currency token specifications.

Extensive e-metering load switch control functions including power-limiting capabilities.

Event triggers and fraud logs.

Various configurable load switch disconnect options as well as remote disconnect and reconnect in the on-line mode.

E460

P160

Economically viable smart grids within municipalities: lessons from local case studies

by Bruce Raw, Peter Atkins and Kevin Kotzen, GreenCape

Smart grid infrastructure in municipalities can improve the efficiency of electricity provision and present new opportunities for economic growth and job creation. This potential business opportunity is currently hampered by barriers which limit municipalities' ability to commit to large-scale roll-out of smart grids and associated distributed generation technologies. These barriers to smart grids have many causes, including a lack of national standards which may result in obsolete infrastructure once standards are finalised, and limited knowledge about the capabilities, benefits and financial viability of these technologies.

The motivation for the GreenCape Smart Grids project was to determine the feasibility of implementing smart grid technologies within Western Cape municipalities, identify barriers to implementation, and facilitate the uptake of these technologies. The underlying aims were economic development through increased electricity network efficiencies, increased local content and job creation.

In 2013 GreenCape ran three case studies, in Drakenstein, Witzenberg and Saldanha, to develop business cases for implementation of smart grid technologies. In these case studies a roadmap was developed for each municipality to help plan the long term future of the municipal grid with respect to smart technology [1, 2, 3]. In 2014 three more case studies will be conducted with a slightly heavier focus on smart grids' role in enabling the green economy, as a sustainable part of the municipal electricity business.

Several lessons were learnt during Geen Cape's various engagements within the municipalities as well as during the modelling and development of the business cases.

2013/14 case studies

In 2013 GreenCape conducted a project to develop smart grid business cases within three Western Cape municipalities. These case studies set out to determine the expected requirements and aspirations for each of the municipalities in terms of their electricity business, identify potential smart grid interventions, explore the business case for a smart grid implementation, and make recommendations on the benefits and challenges for smart grid implementation in municipalities in the Western Cape.

Methodology

This project, consisting of case studies of three selected municipalities in the Western Cape, was developed following a generic five-step process outlined here. As emphasised earlier, the development and implementation of smart grid projects is very case specific, and so the outlines to follow merely describe the process followed. The five-step process is summarised in Fig. 1.

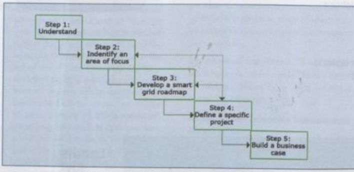

Fig. 1: Diagrammatic representation of business case development process.

Drakenstein

The selected business case project for Drakenstein was a smart metering project to implement a time-of-use tariff for domestic customers, covering the first three areas of the roadmap's initial development, namely: communications platform, smart metering pilot and the extension of the smart metering pilot [1].

The cost benefit modelling of the project for Drakenstein showed that is it possible under the right conditions for smart metering to pay itself off over its lifespan when all the municipal benefits are taken into account.

During the modelling process we learnt that the viability of a smart metering implementation can shift dramatically, depending on the tariff used and the customer's response to this tariff. A graph of the cumulative net benefit of the proposed project can be seen in Fig. 2, showing a payback period of just under 15 years, giving the project a net present value of R76 000.

The business case for smart metering is not particularly strong if you consider only the financial benefit for the municipality. While the project should pay itself off, it does not offer a large return on investment during the meters' lifespan. However when the customer savings are taken into account, the result is dramatically improved.

This showed that there is great economic value to be gained through load shifting even if the direct value to the municipality is low. This value requires users to both understand the tariff, as well as have sufficient incentive to shift load.

Saldanha

The business case project for the Saldanha Bay municipality explored a substation metering proposal followed by a fault detection proposal. The project covers the first three areas of the roadmap's initial development, namely: communications platform, substation metering project and mini-substation fault detection [2].

The implementation plan for the Saldanha project was required to be split into sections of work that could be implemented and see benefit within three to five years. This restriction made it difficult to build a plan to roll out smart grid technology because individual implementations add little value as stand-alone solutions.

Witzenberg

The Witzenberg case study focused on the impact of net metering as opposed to the current situation of detent-free mechanical meters (allowed to spin backwards) [3]. The proposed feed-in tariff, in which electricity is fed back onto the municipal grid at cost (at the same tariff as paid to Eskom by the municipality), shows the reduction in profit from a typical customer installing PV is reduced by about 19%. This means that the meter cost is easily recoverable.

The business case thus calls for a well thought out feed-in tariff to mitigate potential threats to municipal revenue, while also encouraging the uptake of renewable energy generation. This will contribute to national efforts at sustainable development – particularly through changing the country's energy mix and thereby reducing emissions from electricity provision.

2014 case studies

In 2014 GreenCape will be running three additional case studies. These case studies are planned to focus on the role of smart grid technologies in enabling the green economy while still being part of a sustainable municipal electricity business.

These new case studies will look at the interactions between various grid technologies and the rapidly changing space of distributed and embedded generation and energy efficiency.

Smart metering

Smart metering forms a large part of a smart grid, and as such is a key component when looking into smart grids. It was quickly identified that the lack of stable standards was a large barrier for most municipalities.

The smart grids project team has also been involved in researching and developing smart metering standards. It has been focusing specifically on the development of a standard for a smart split[1] prepaid meter.

At present there is limited availability of suitable smart split prepaid meters. This is because split prepaid meters are not widely used internationally and the fragmented South African market is not currently large enough to warrant making a special meter – even if an agreed South African standard was in place. The situation might change in the light of the recent designation of smart meters for local procurement – which will encourage local manufacture [4].

This standards process is ongoing, and we will continue to assist the process in any way we can.

Currently the business case for smart meters is not very strong for the municipalities we have looked at, as the high price of the meter makes it difficult to recover costs fully. Smart meters do add significant saving opportunities for the customers, however, so if funding becomes available that does not require short pay-back times, smart meters are very attractive.

It is also possible to get a much stronger business case if the rollout is done only to replace meters that are being replaced anyway rather than a full replacement project.

Lessons learnt: building business cases

One of the most visible lessons learnt from business case modelling is that the financial case for smart grid technologies is not always easy to build [5]. Many of the benefits gained from technologies such as smart metering and outage management do not come in the form of direct financial return to the utility. A large part of the benefits gained directly benefit the customer. Nevertheless, due to the fact that service delivery is a core principal of municipalities, these benefits serve as good motivation for moving towards a smart grid. It is important when building a business case for a smart grid technology that these customer benefits be included.

Note that the municipality's objective is not to make a profit, but to provide the agreed service delivery in the most cost-effective way. Customer benefits can be regarded as a part of service delivery, so in this sense the municipality's decision to invest in smart technology mainly for the benefit of the customer is political.

The difficulty with the motivation of these technologies, based purely on service delivery, is that they are competing for funding with other projects that also offer improved services to the community. Smart grid technologies do, however, offer significant value to the municipality outside of service delivery which, when combined with the customer benefits, can lead to large benefits for the municipality, at little or no net cost.

Pilot projects

One difficulty is identifying where all of the gains for the municipality will be found. There are many variables that can impact the outcome of the project by very large margins, such as the user's response to smart metering. Without accurate information it is almost impossible to predict exactly what value will be gained from a project and, in our case studies, it was seen that this information will only be gained after implementation of the project has begun.

It is for this reason that, in all our project plans, we suggested starting with a pilot project or small initial rollout so that risk can be properly managed, and maximum benefits can be drawn from the investment.

Tariffs

During the modelling process it was noticed that the tariff structure impacted the business case far beyond what was initially expected. While it was always obvious that adjusting the tariff, would have a significant effect on municipal revenue, when looking at time of use tariffs it was quickly seen that this effect extends past just raising or lowering the cost of electricity.

There are links between the tariff and the user's response that make modelling the

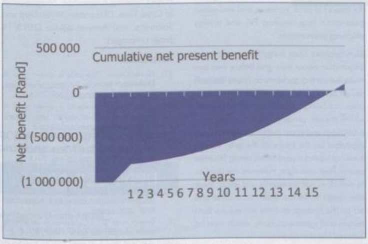

Fig. 2: Cumulative net benefit of project.

Note 1: Split meters have the meter itself in a secure kiosk outside the customer's premises and a display unit plus a keypad inside the premises.

effects of a tariff change complex. Increasing the differential between peak and standard pricing not only impacts the revenue collected when the tariff is implemented and the change in revenue when a customer shifts load, but also the likelihood that the customer will shift their load. Making the differential too high means that the municipality will lose revenue if the customer shifts load and making it too low provides no incentive for the customer to shift load.

In the modelling done for Drakenstein, it was found that it is possible to make a tariff that provides the customer incentives to shift load and increases municipal gross electricity profit while still ensuring that the average customer bill is not changed when shifting on to time of use.

This tariff development process requires a good knowledge of the consumption of the users that are going to be on the time of use tariff. Acquiring detailed consumption data and carrying out appropriate modelling is not a trivial process; however it can make a large difference to the success of the tariff.

Road map

The high cost of smart grid technology makes it prohibitive for a municipality to roll out an entire smart grid in a single project. For most municipalities the cost of upgrading to a smart grid is many years' worth of budget.

This means that smart grid interventions need to be staged in manageable parts and because all of the parts of a smart grid derive additional benefits from the other parts, how the interventions are selected is important.

Preparing a long term vision and roadmap for progression to a smart grid will allow municipalities to better manage their choices as they move forward and enable them to make the best selection of technology to suit their needs at each stage [6].

Conclusion

The smart grid projects have highlighted some of the difficulties which will be faced by municipalities looking at moving towards smarter grids. While most Western Cape municipalities are not yet at the point where it makes sense for large investment into smart grids, it is clear that the path of the grid is moving towards smarter technology. It is important for municipalities to develop a roadmap for moving their grid towards a smarter grid and plan their upcoming spending wisely. The business cases for smart meters and other smart grid technologies are not always viable just yet, but as technology becomes cheaper and energy more expensive, the cases get better. Nevertheless, if customer

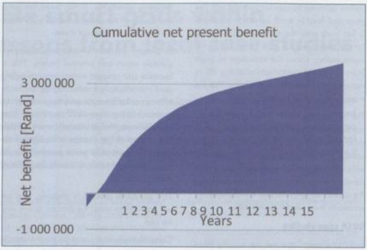

Fig. 3: Cumulative net benefit of project with customer savings included.

and municipal benefits are included in the business case, smart meters do make sense and the decision to invest then becomes a political service delivery decision.

The tariff design for time of use tariffs has a much larger impact on revenue and is a lot more complex than standard tariff design. Residential customers do not have the same flexibility as large industrial users in terms of shifting load, and as such require a different tariff for time of use to be successful. We strongly suggest that great care be taken in the development of residential time of use tariffs. Time of use tariffs, if designed and implemented correctly, can increase a municipality's financial stability and ultimately allow them to insulate themselves against the impact of price increases and embedded generation (e.g. rooftop PV) and energy efficiency interventions.

Municipalities need a significant amount of information about their grid before they can make the correct decisions on issues like tariff design and capital expenditure. This data is often not being measured at all at present, which means projects like metering mini substations and smart metering pilots are very important for the future of the grid, despite them not having a particularly strong business case in their own right. However, the data on its own does not necessarily add value, there also needs to be the ability to analyse and act on the findings and this will require both people and systems capacity, which must be factored into the projects.

Implementing smart grid technology in a "big bang" manner is not usually financially feasible and can be risky. A phased approach following a roadmap is safer and more financially viable. In adopting a phased approach, it is necessary to understand that the individual phases don't necessarily each pay for themselves but, taken together, they do.

Acknowledgements

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Journey towards a smart utility: An eThekwini Electricity perspective

by J Hunsley, J Pershad, M Mthembu, S Jagannath, V Maistry, S Sewchurran, and K Annamalai, eThekwini Electricity

The benefits of a smart grid, including improved customer service, network reliability and improved outage response, exceed the current challenges experienced by eThekwini Electricity. This paper discusses the approach followed by eThekwini Electricity in achieving its objective of a smart grid and highlights the challenges encountered. These challenges are not unique to eThekwini Electricity but impact on all other electric utilities within the South African region. The paper further discusses the achievement of a fully automated network which can ensure two-way flow of electricity and information. The implementation of various projects to meet the smart grid objective is also highlighted.

eThekwini Electricity is one of the largest and most respected utilities involved in the transmission and distribution of electricity within South Africa. The licence area of supply within the municipal boundary covers just over 2000 km². eThekwini is the only metro within the country which operates at a voltage of 275 kV, receiving power from Eskom at five infeed substations disbursed around the municipal boundary.

The vision of the utility is to be a leader in electricity distribution providing energy for the future. This vision is underpinned by its overall strategy to develop the utility as an undertaking that maximises the value of its electricity supplies and makes effective use of all its resources (see Fig. 1).

Current challenges in a municipal environment

eThekwini Electricity prides itself as a progressive utility with highly skilled technical personnel who continuously explore innovative ways of improving the effective management of the utility. The implementation of these innovative ideas have placed the organisation as one of the leading utilities within the electricity distribution industry of South Africa.

The major strides and gains made in the technological space are, however, at times overshadowed by the vast majority of challenges faced by the utility. These challenges include:

- Provision of electricity to customers within informal settlements.
- Theft of infrastructure.
- Theft of energy.
- An ageing network with increasing maintenance costs and poor maintenance practices.
- Unplanned outages from overloaded networks compounded by a rapid growth in demand and geographic expansion.
- The lack of institutional memory as a result of experienced employees retiring without the necessary skills transfer to other employees or systems. This is resulting in a shrinking workforce that must work more efficiently and cost effectively.
- Legacy information technology systems with fragmented applications. Undetected inefficiencies and misallocations of resources need to be identified.
- Increasing compliance requirements with respect to quality of supply and service, finance, health, safety and environment.

However, eThekwini Electricity continues to be motivated and committed due to its recognition of the benefits of achieving a smart grid which, in the main, includes improved customer service, network reliability and improved outage response.

Smart grid workgroup

eThekwini Electricity has and is implementing various projects with the aim of improving the smartness of the grid and managing the grid more effectively. The approach currently would seem to be fragmented, hence the need to consolidate all efforts to achieve a common objective. The need to consolidate all initiatives and develop a common vision and strategy for the realisation of a smart grid led to the establishment of a smart grid workgroup in May 2013.

The smart grid workgroup is directly accountable to the electricity executive and aligns its activities with the municipality's Smart City vision. It also aligns with and provides input to the South African Smart Grid Initiative (SASGI), established as a mechanism for the strategic direction and implementation of Smart Grids within South Africa.

The scope of the work group includes:

- Developing a high level vision of what an eThekwini smart grid might look like and the challenges it would help addres.

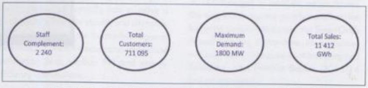

Fig. 1: A break-down of staff, customers, demand and sales at eThekwini Electricy.

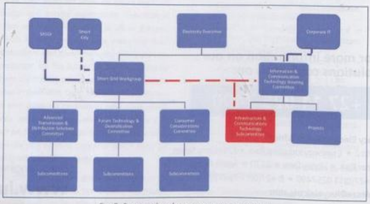

Fig. 2: Smart grid workgroup governance structure.

Fig. 3: Committees and their scope.

Fig. 4: Smart grid maturity model levels and domains.

- Evaluating options pertaining to grid intelligence.
- Ascertaining the level of international experience of smart grids to date and future plans.
- The assessment of smart grid related developments within the South African electricity supply industry.
- Establishing a baseline position i.e. assessing the current network capability for smart grid applications.
- Proposing research, development and deployment opportunities that should be pursued in the immediate future to ensure readiness to deploy smart solutions.
- Considering pilot projects and evaluating the results from pilot projects.
- Determining the high level costs and benefits of developing smart grids.
- Providing input to standards and specifications.
- Developing a smart grid action plan which will:
  - Set out detailed actions required to implement the strategy.
  - Define roles and responsibilities for the different smart grid role players.

Committees

The committees serve to provide the platform through which the actual activities of the workgroup are executed. The scope of the various committees is elaborated further in Fig. 3.

These committees receive their mandate from the smart grid workgroup. The interaction within the committees serves to break down the silo mentality and streamline the initiatives.

Smart grid strategy development

The establishment of a consolidated governance structure for the utility with the workgroup as the driver of the smart grid journey has led to the need to develop a strategy as its framework and tool. The development of this strategy is not undertaken in isolation but dovetails with the utilities overall strategic plan as well as the cities smart vision.

The elements of the strategy will include, but not limited to:

- Roadmap and action plan.
- Technology plan.
- Overall budget.
- Resources required.
- Consolidated approach.

Smart grid maturity assessment

As utilities consider undertaking the journey towards achieving a smart grid, and having understood what a smart grid is and why it needs to undertake this journey, there are three questions which it needs to ask itself:

- Where am I now – an "as is" analysis of the utility understanding its smart grid maturity.
- Where do I want to go – "to be" state of the utility by developing a vision.
- How do I get there – "roadmap" – development of a strategy.

eThekwini recognised the need to determine its "as is" condition and therefore took advantage of the opportunity provided by SASGI. This involved the assessment of the utility with regard to its smart grid maturity. The methodology used was via a model developed by the software engineering institute of the Carnegie Mellon University based in the United States of America. This model has worldwide recognition and has been utilised by numerous utilities worldwide.

The smart grid maturity model – essentially a matrix of almost 200 outcomes, capabilities and benefits, plotted and tracked in various work domains – progresses through five levels of maturity. Not every utility will need, or want, to go to the last level. Depending on their situation, a utility can select which level is optimal for their smart grid vision. Level 5 (Fig. 4) for example, perpetuates innovation into new frontiers of the energy business [1].

With this general progression of the "levels of maturity" in mind, let's take a look at the eight domains in your utility that are impacted by the changes brought about by the smart grid transformation. The core business areas that are most affected in a smart grid transformation are reflected in Fig. 4 [1].

The outcome of the assessment in some ways provided an independent confirmation of what the utility had itself acknowledged, among other areas. The eThekwini team is committed to explore opportunities to enhance their overall business performance and sustainability. Numerous technology implementation initiatives are taking place within eThekwini Electricity which is commendable. The technology implementation initiatives are not necessarily taking place as an integral part of an integrated smart grid strategy. The survey results reflect the level of "inconsistency and absence" of an integrated technology deployment approach (level of silo approach). The approval and adoption across Lines of Business (LoB) of the smart grid vision, technology deployment plan and an integrated implementation strategy, will significantly contribute to the smart grid maturity level of the utility. It is essential to focus on employee participation and the business structure alignment to support the smart grid journey. The eThekwini team demonstrated commitment to the smart grid maturity assessment process and the participation was outstanding.

Fig. 5 provides a representation of eThekwini's current maturity. While this outcome may be seen as bleak, however, it's viewed as an opportunity for improvement and growth with an appreciation of the path which the utility must travel over the next few years to realise its objective of modernising the grid.

Implementation of various initiatives

As a utility embarks on this journey towards achieving smartness/modernisation of its grid, it's important to get the building blocks right. Fundamental to this is having an appreciation, as a utility, as to the ownership of its assets, where are they located, what their condition is and what their useful life is. The utility has observed that the creation of a framework to manage and monitor the performance of these assets is key.

With these fundamentals in place, a utility can now begin to consider introducing smartness into the grid such as:

- Introduction of intelligent devices and sensors (automation).
- Installation of various communication mediums between on-site devices and the back-end (control centre).
- Modernised the metering infrastructure to enhance the customer experience.
- Exploring different forms of generation and their impact on the grid.

The next section of this paper highlights the work which eThekwini has undertaken and is in the process of implementing in realising this objective of achieving smartness.

Asset management

True smart grids can only be successfully implemented if you have access to information about the network, communicating it to the right people, systems and customers and enable self-healing functionality and intelligent decision making on the network [2]. The asset management initiative deliverables support these fundamental principles, thereby allowing eThekwini Electricity to harness the benefits of smart grids.

At the core of the asset management initiative was the asset field verification and identification which was primarily instituted to comply with GRAP17 financial regulations. However, the exercise also enabled asset management fundamentals by providing reliable and detailed asset information. This information was captured and will be stored against an equipment hierarchy that will link the technical equipment register to the financial asset register. This would enable transparent daily transactions of new additions, operations and maintenance and disposal, allowing the information to be available for more informed decision making.

In order to overcome the challenges of information duplication, leading to conflicting information and lack of information maintenance processes, a draft technical information system framework was established. This will assist eThekwini Electricity in moving towards integration and development of information systems and establishment of best practise processes which will mitigate technical information disparity. In support of the technical utility information system framework, a draft technical utility data model was defined. The technical data model will facilitate an environment where information and information ownership is well documented and agreed upon. It sets the responsibilities for the various sections and personnel involved to maintain adequate data. The technical utility data model provides the perfect foundation for future system expansion and integration planning.

As can be seen from Fig. 6, information integration is required to ensure all the systems have a similar and accurate view of the required asset's information, and that no one system hosts all the required information about the asset. Also various systems will play a role together to provide a comprehensive representation of all asset information, which can be viewed through business intelligence tools/software [2].

The benefits achieved from improved asset management practices include:

- Improving the network performance and service delivery, thereby enhancing customer satisfaction and improving health, safety and environmental performance.
- Optimising return on investment and obtaining value for money. Cost savings can be achieved on refurbishment by extending the equipment life cycle due to improved maintenance procedures, which would have an added benefit of reducing insurance costs and levies.
- Legal, regulatory and statutory compliance through controlled and systematic processes (KPAs and KPIs).
- Improving risk management and corporate governance and providing a clear audit trail for the appropriateness of decisions taken and their associated risks. There should be a balance between engineering, operational and financial risk.
- More efficient and effective procurement would ensure that the supply chain would be better managed.
- Ensuring that sustainability is actively considered as part of asset utilisation and selection.
- Improving productivity as a result of better planning and targeted human resource development.
- Improving decision making as a result of better available information with respect to infrastructure, people and processes.

GIS landscape

The intelligence of the smart grid relies critically on geospatial data to represent and track the locations of numerous devices within the connectivity model of the distribution system [3]. Traditionally the network reticulation records at eThekwini Electricity were stored in a computer aided design (CAD) package. The transformation from CAD to a geographical information system (GIS) environment incorporated metadata and additional intelligence to the database.

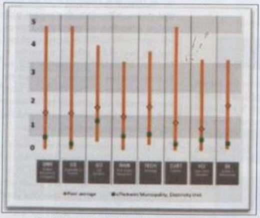

Fig. 5: Smart grid maturity model peer community.

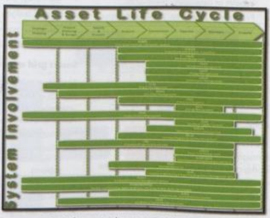

Fig. 6: Systems involvement – asset lifecycle [2].

MARKET OFFERING
ZEST Electric Motors
Electric Motors
Variable Speed Drives
Soft Starters
Transformers
LV Switchgear
Diesel Generator Sets
ZEST WEG Group
ZEST Energy
Power Generation & Energy Solutions
Substations & Electrical Infrastructure
Mobile Power Solutions
ZEST ENERGY
Shaw Controls
Packaged Switchgear
Motor Control Centres
E-Housing
Containerised Substations
SHAW CONTROLS
WEG Transformers Africa
Mini Substations
Transformers
Switchgear
WEG
EnI Electrical
Supply and installation of electrical instrumentation and control/PLC SCADA
Construction specialist in all major sectors across Africa
EnI
SUPPORT
WHERE YOU NEED IT, WHEN YOU NEED IT
24/7 technical back-up
Fully qualified technicians
5 Fully equipped training centres across Africa
187 site visits into Africa per year
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GIS at eThekwini Electricity provides a spatial platform for the technical records of all the existing network infrastructure. An updated dataset is reliant on the receipt of accurate as-built drawings from the various works branches and is supported by the Master Data Change process hosted by the Asset Care Centre.

As more branches and their divisions are exposed to and interact with the GIS they are beginning to realise the benefits of having a fully connected geospatial network data model. The revised data model has provided a platform to integrate the GIS data with other enterprise systems of the organisation. It has also addressed the issues of network connectivity in the GIS and provides the ability to perform network tracing.

Objective

The main objective of the initiative is to have a fully connected network of the high voltage, medium voltage and low voltage electricity reticulation in GIS and to have a real-world geographical representation of the electrical infrastructure. Secondly, it provides a platform which will allow for the interaction with other enterprise systems of the organisation, viz. outage management system, revenue billing system, enterprise asset management system, customer information system, etc.

Progress

A new data model was designed to host the additional data from the asset management field verification project. This data model incorporates existing eThekwini Electricity's underground layers, (i.e. underground cables, communications infrastructure, cable ducts and cable joints, and terminations) that were excluded from the asset verification project. In addition to the data that was collected in the asset management field verification project, the data was further enhanced with existing data from the eThekwini Electricity dataset. ArcVisio templates were designed to replicate the equipment in the field and assist GIS capture process.

The enhanced data model has been executed in a third of the network, viz. the southern region. Electrical network connectivity for components of the medium voltage and low voltage equipment has been achieved in this model.

Challenges

Some of the challenges experienced include:

- Very complex dataset with extensive attributes that needs to be maintained.
- Reliance on the entire organisation to provide data.
- Data discipline is a problem and needs to improve throughout the organisation.
- The organisation needs to adapt to new data model.

Benefits

Assets are better managed by having an accurate spatial record. A fully connected geospatial network database supports a quicker response in spatially locating underground infrastructure and fault finding. This also promotes efficient planning for new construction and extension to the network and for planned maintenance.

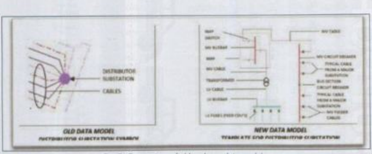

Fig. 7: Comparison of old and new data models.

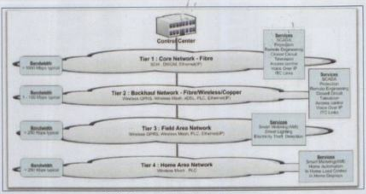

Fig. 8: Communication networks strategy.

Communications infrastructure

In considering the role of communication networks in the smart grid, it's important to emphasise that the first enables the second. Adding intelligence to the electric grid primarily means automating various grid functions. And automation isn't possible without communications networks that enable a two-way flow of data [4].

Historically all system communication within eThekwini's electrical network was via a copper pilot system consisting of cables with varying numbers of cores.

As the copper system aged, it became susceptible to faults which are very costly to repair. As the pilot cables were also unable to meet the communication demands of a modern utility, an overall long term communication network strategy was adopted in 1994 which included implementing fibre optic based systems and wireless systems.

A new communication networks branch was established to concentrate on the rapidly increasing communication requirements of the electrical network.

Objective

eThekwini Electricity's communication network strategy is to establish a private, integrated multi-tier, hierarchical communication network as shown in Fig. 8.

The system is required to cover the entire area of supply. It needs to be reliable, secure and scalable. As a modern communication network it will be required to provide overall high bandwidth and low latency performance. To ensure efficient and effective operation and maintenance, the system will be required to be fully manageable through a centralised management system.

Benefits of a private communication network

Electricity utilities have a long tradition of owning and controlling their own communications networks for mission-critical applications because of concerns about reliability, safety, security and cost. Even in cases where the cost – in terms of capital and operational expenses – is greater than a non-utility alternative, the guarantee of reliability, safety and security inherent in a proprietary utility-owned network often trumps cost concerns (see Table 1) [4].

Progress

Fibre optic cables were installed inside the earth wire on overhead line systems, (optical ground wire or OPGW), as part of refurbishment projects handled by the HV operations department. Underground fibre optic cables were also laid together with electrical cables between major substations.

The second objective was to install a fibre optic SDH multiplexing system between major substations, and to provide connections for protection schemes, SCADA, remote interrogation of protection relays, quality of supply recorders, security systems, data communications, and other services of the electrical network. This has been achieved, and all majors are now reachable and are serviced by the multiplexer system. In addition, a layer 3 data network has been at these major substations to accommodate the new requirements for Ethernet services such as distribution automation traffic backhaul, CCTV and access control.

The fibre optic system is also used for administration systems. All eThekwini Electricity depots have been connected using dedicated fibre links. In addition, a commitment has also been made to make a pair of fibre cores available on each route for use in eThekwini Metro's broadband venture, MetroConnect.

Cellular radio technology was introduced to provide the communication channel back to the control centre. This provided communication links to the approximately 800 distributor substations of the intermediate 11 kV level of the electrical system. Although not under internal control, this technology was accepted as an interim solution due to the readily available infrastructure and extensive coverage which enables fast roll-out throughout the region.

These allowed the ability to connect mini-RTUs and RTUs of new IEC61850 distributor substations to the control centre, for automation purposes. This cellular system will most probably also be initially utilised in linking up mini substations, autoreclosers and other remote equipment in the electricity system.

A focus has also been placed on network management with modern systems being procured to support the evolution towards Ethernet services within the electric utility environment.

The current focus is on setting up a private tier 2 communication network to cater for the 11 kV level of the electrical system. Progress has been made by initiating a proposal to install fibre optics to all distributor substations, as well as in undertaking a pilot project to rollout a carrier grade wireless mesh solution.

Challenges

Challenges in deploying, operating and maintaining communication infrastructure include:

No.	Concept	Description
1	Control	Since the utility owns the network, the utility is in complete control, able to determine quality of service (QoS) and packet priority to ensure adequate bandwidth for the most crucial business applications at all times. In addition, the elimination of public traffic removes opportunities for network overload that could render the network unavailable, for example, during a disaster. This is particularly important for mission critical applications such as supervisory, control and data acquisition (SCADA) and tele-protection.
2	Future proofing	Private utility communication networks are not subject to the constant protocol changes that take place for example in commercial cellular networks, ensuring that the equipment you purchase today can remain in service over the 10 to 15-year expected lifecycles for electricity infrastructure.
3	Security	Since the network is privately owned, the utility can deploy, enforce and manage standard security policies to provide the right level of protection for company data. To re-iterate, this is particularly important for mission critical applications such as supervisory, control and data acquisition (SCADA) and tele-protection. This will also play a critical role in the introduction of smart metering and other valued services as both customer and consumer information will need to be secured.
4	Coverage	The utility can design the network to ensure coverage wherever it is required.
5	Capacity	The utility is in charge of managing capacity. As additional applications are added, the utility can add capacity as needed. The capacity requirements will continue to grow as the utility adopts various smart grid technologies and at its own pace.

Table 1: Benefits of a private communication network.

- Recruitment of competent technical staff, compounded by trying to support aggressive employment equity practices.
- Lack of support from administration sectors of the organisation, ranging from supply chain management to approval of dynamic organisational structures to cater for evolving business needs.
- Adoption of the correct standards and technologies as new ones continue to emerge.
- The need to support legacy systems.
- The reluctance or inability to accept change within the organisation.
- Missing core functions, processes and fundamental practices ranging from work planning and control cycles to project management.

Lessons

The largest lesson learned was the need for an overall strategy within the organisation to ensure that the massive needs and changes required to implement a smart grid is met. An example would be eThekwini Electricity's initiative to update its medium voltage planning and construction processes to include the planning of communication infrastructure to accommodate future smart grid applications. Attention must be paid to the operation and maintenance strategies of systems as these are often overshadowed by the installation and commission phase of a project in excitement of adopt new technologies.

Distribution automation

eThekwini Electricity has a long-term goal to obtain full Supervisory Control and Data Acquisition (SCADA) visibility throughout the distribution network, therefore aims to install intelligent devices to remotely manage and control all medium voltage equipment in the distributor substations, ring main units, autoreclosers, mini substations, and kiosks, to ensure network reliability. eThekwini also aims to install through fault indicators to monitor the overhead mains (OHM). The distribution automation project has been broken down into three phases and each phase further subdivided into the respective order of priority

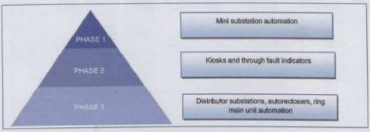

Fig. 9: Distribution automation project breakdown.

Fig. 10: RTU type A.

Fig. 11: RTU type B.

for which the DA project is currently being deployed (see Fig. 9). Distribution automation aims to ensure a secure, reliable and safe network in alignment to a smarter grid.

Benefits

Improves data acquisition for engineering and strategic planning of the network by making valuable information available to the planning and construction divisions, who will further influence the future reinforcement and operation of the network.

Improves network performance by reduction in system outages and greater security of supply. This is made possible by the intelligent SCADA system which allows the controllers to monitor and manage the MV network in real time.

Improves operator efficiency and safety – controllers are made aware of faults as soon as they occur by receiving alarms. The operator can therefore respond quicker to a fault, monitor the loads at each substation and remotely control switchgear.

Improves the controller's visibility to unsafe or insecure situations on the network.

The intelligent devices allow for early detection of equipment failure and assists in fault location, and improves restoration times.

Enhances overall customer service – improved detection and restoration of faults hence, reduced outage times and feedback to customers on the status of outages.

Progress

Remote terminal units (RTUs) have been installed and commissioned in 455 distributor substations from a total of 755. A total of 507 of these distributor substations have been wired. The main objective of this project is to enable remote monitoring and control of distributor substations and these RTUs allow for remote data acquisition and control to these substations. The status of these sites is regularly monitored to ensure communication to the intelligent devices. Communication to the RTUs was made possible by the installation of Internet Protocol (IP) Modems using GPRS. The advantages of IP communication include the ability for engineers to do updates, configuration changes and remote diagnostics of faults without the need to drive to site, so improving the response times to faults. Open VPN was implemented to take care of security vulnerabilities which GPRS introduces.

A total of 71 ring main units have been installed where nine of these sites have been commissioned and a total of 74 autoreclosers have been installed with SCADA functionality, but none have been commissioned.

Two through fault indicator (TFI) sites have been configured and commissioned for testing purposes to monitor the performance of the devices and to ensure they meet eThekwini Electricity's requirements. The TFI will serve as an indication to the personnel as to where a fault occurred on the OHM. If a fault occurs, the TFI will trigger an LED on the sensing unit mounted on the line and an alarm will be sent to the control centre to notify the controllers that a fault has occurred and the faults team can then be dispatched as soon as possible to repair the fault.

The kiosk pilot site has been tested and commissioned. The first batch of kiosks is currently being wired and prepared for the mini RTU installation. This will allow the controllers to detect when a fuse is blown and obtain earth fault indications, as well as the current loads of the substation.

Challenges

Physical security, vandalism and theft on the electrical network are a growing concern. Communication media in some locations are unreliable due to the low signal strengths.

Advanced metering infrastructure

The advanced metering infrastructure (AMI) programme is responsible for the implementation of smart metering which entails installation of smart meters, associated equipment such as communications modem, customer information units (CIUs) and data concentrators (DCs), as well as multi-vendor master stations (MVMS) and meter data management system (MDMS). Integration of all these components will ensure a seamless end-to-end bi-directional communication flow. This initiative will enable eThekwini Electricity in its effort to achieve their broader objective of implementing smart grid in their areas of electricity supply. AMI will also ensure consistency and optimisation of similar metering initiatives within eThekwini Electricity. The AMI programme will align to the overall eThekwini Electricity smart grid objective which entails a sustainable and medium-to-long term strategy. This strategy is also an essential part of eThekwini Municipality overall vision of creating, among other priorities, a safe, accessible, environmentally and economically sustainable city by eventually achieving a smart city objective.

The eThekwini AMI solution:

- Relies on the implementation of a multi-vendor master station.
- Relies on the implementation of a meter data management system.
- Requires AMI meters.
- Requires one or more field installer (service provider) to install the AMI meters.

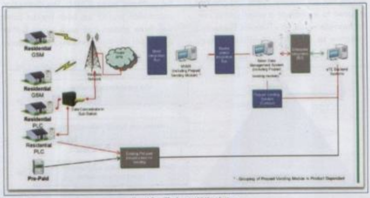

Fig. 12: eThekwini AMI solution.

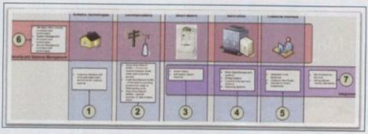

Fig. 13: Conceptual compartmentalisation of solution components.

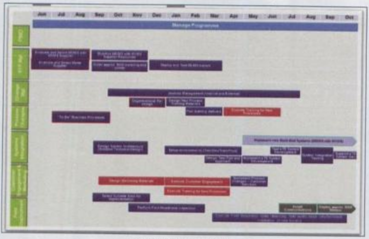

Fig. 14: AMI high level timeline.

- Requires communication infrastructure to facilitate communication between meters and the MVMS. The current view is that this will be achieved through GPRS over eThekwini's existing private APN.
- Will leverage its existing prepaid vending solution.
- Will leverage eThekwini's existing prepaid infrastructure for prepaid vending.

Fig. 13 shows the key elements in the end state.

Table 2 provides a detailed description of the various components outlined in the conceptual design reflected in Fig. 13.

Embedded generation

Load shedding and the rising electricity prices have forced customers to become more aware of their electricity usage. The pay back periods and viability of small scale embedded generation projects have also become more feasible. Small scale generation projects, especially rooftop photovoltaic (PV), are now becoming a popular sight within the city of Durban. Customers are procuring pre-packaged solutions either locally or shipped from international suppliers. With little technical knowledge and good handy man skills, the pre-packaged plug and play solutions become a kilowatt-hour generating machine as it absorbs the sun's rays.

There seems to be a reluctance to couple batteries to the generation systems with the tendency to synchronise the system to the municipal grid. There are numerous advantages in such a scheme, as it allows for the grid to act as a virtual battery when the local generating plant produces more kilowatt-hours than the household requires. This eliminates the need for expensive battery technologies and related maintenance/ disposal procedures.

While the advantages make synchronisation a logical choice, it also triggers the need for technical, safety and regulatory compliance. With this concept being relatively new, there is lack of clear guidance in terms of how these generators need to be treated. Industrial role players are trying to propose solutions; however there are many challenges to overcome prior to the introduction of a holistic solution. It is of extreme importance that a national framework be introduced immediately, as reverse power flow onto the network creates safety and technical hazards, among other issues.

eThekwini Municipality has come under tremendous pressure from the public to introduce a mechanism to allow for the export of generated energy. Many installations have gone ahead without approval from the city and this has resulted in meters reversing, posing a severe financial risk to the municipality. Unknown reverse power flow also creates a safety hazard. If left unattended, the situation would become unmanageable.

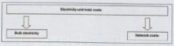

Fig. 15: Costs.

In an effort to gain control and manage these installations better, eThekwini Electricity has taken bold steps in implementing an interim small scale embedded generation framework. Some of the steps taken include the proposed implementation of a residential embedded generation tariff to create a simple buy-back mechanism for generated electricity.

In providing electricity supply to any residential end-user, eThekwini Electricity levy charges by means of a tariff structure to recover costs incurred in providing such a service. There are a variety of costs, however. For the purpose of simplicity within the context of this paper, these cost can be viewed in Fig. 15.

The bulk electricity costs refer to the costs that are paid to the generator of the electricity which is Eskom. While the Network Costs refer to the fixed costs incurred by eThekwini Electricity which includes costs such as repairs and maintenance, salaries, meter reading and related costs. Stemming from the above, it can be concluded that there are fixed and variable costs associated with a supply point, irrespective of the direction of power flow. Residential users currently pay for both costs via a single rate energy charge (per a kWh).

The introduction of this new tariff allows residential customers to consume electricity from the grid as well as export generated electricity to the grid. As a result of implementing such a mechanism, the municipality runs the risk of a financial loss. If the customer generates as much as consumed, then the payment to the municipality is zero. To ensure no free riding on the network and the risk to the municipality is limited, a network recovery charge is needed. The current tariff recovers the network charge as electricity consumed. Whilst this is not cost reflective, it is workable and has been successful in recovering the network charge in the past. To ensure consistence and equal treatment amongst the residential sector, it was proposed that a network access charge be recovered via an energy usage mechanism.

All generation sites need to be metered and metering of these small scale embedded generation sites are done by electronic bi-directional meters which record both the import and export kilowatt-hours. These readings are then fed into the billing system which had to be programmed to manage this complicated residential embedded generation tariff.

With regards to the license requirements of small scale embedded generators, eThekwini

No.	Component	Description
1	In-home technologies	Customer interface units display and load control devices at the customer premise, interconnected with the utility's systems via a home area network (HAN).
2	Communications	Network technologies that interconnect the various smart meter infrastructure (SMI) components.
3	Smart meters	Smart meters and the associated AMI master station system.
4	Back office	The eTE systems providing customer management and billing functions.
5	Customer interface	System providing direct interface with the customer such as integrated voice response (IVR) and the customer web portal.
6	Security and systems management	Security and other management systems used to maintain, monitor and manage the infrastructure and application environment.
7	Integration	Enterprise integration architecture (EAI) is the integration framework composed of a collection of technologies and services which form a middleware to enable the integration of systems and applications across the enterprise.

Table 2: Conceptual component descriptions.

Electricity together with SALGA and the AMEU have put together a request to NERSA regarding generation license requirements for small scale embedded (<100 kW) generators and still eagerly await the outcome of this request.

At the outset of this journey, there were lack of policy and guidelines guiding embedded generation but over the years, there has been progress in the creation of guideline and policy towards embedded generation namely; NRS 097, South African Renewable Energy Grid Code, SANS 10142-3 which eThekwini Electricity has been a part of. The eThekwini Electricity framework is in line with the latest codes and standards to ensure that all generators comply with the necessary regulations.

A simple application form that can be obtained from the eThekwini Electricity website has to be filled in by any resident wishing to synchronise with the municipal grid. The form needs to be furnished with details of the technical specification of all the generation equipment. This is then evaluated and if it meets all the criteria then approval to connect onto the grid is issued. Upon completion of the installation, a certificate of completion needs to be submitted to eThekwini Electricity signed off by a professionally registered person to certify that the installation complies with all the technical and safety standards.

The above simple process to promote small scale embedded generation has been developed but is pending the approval of the Residential Embedded Generation Tariff by NERSA and clarity on the generation license requirements.

Failure to implement a policy of this nature will result in the non-promotion of small scale renewable technologies by local government. This is unfavorable as national Government has pledged its support to promote renewable technologies.

Conclusion

The challenges in a municipal environment are immense, especially when electricity provision is an essential service and a cash-cow. Due to these challenges, it is quite easy for a utility to get bogged down in dealing only with its operational mandate as opposed to having a strategic view on its long term vision.

This paper has clearly demonstrated eThekwini's intention to modernise its electric grid over the m edium to long term. This intention embraced by the utilities executive management and is driven at a senior level with a strategic focus. There is acknowledgment that this is a long term journey however, eThekwini has commenced its walk on the path towards a smart utility via a co-ordinated and systematic approach.

Collaboration by the various stakeholders within the industry is crucial in ensuring the successful achievement of a smart and modernised grid within the country. The Department of Energy is key to provide the policy imperative and budget where necessary; SASGI to consolidate national efforts, provide strategic direction and support the development of standards; National Energy Regulator of South Africa to provide the regulatory framework; Manufacturers via the innovation and appropriate technology; and buy-in from the Customer.

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Municipal tariffs: where to from here?

by Hendrik Barnard, Elexpert

Municipal electricity tariffs are in a shambles: NERSA tariffs (IBT) have created chaos beyond comprehension. Electricity is being sold at prices below the Eskom purchase cost. More and more low usage customers are increasing the subsidy burden. High usage, overcharged customers are converting to alternative energy solutions. NERSA is stipulating large customer tariffs at Eskom plus 20%, thus depleting any option of making a surplus.

Despite all of this, large profits are being hidden. This paper will describe these problems and propose an approach in line with the government's Electricity Pricing Policy, where a fair deal is given to all customers and yet the municipality is ensured of a fair income and profit.

Domestic cost of supply

Before assessing various issues, I will do a short cost of supply (COS) study for typical domestic customers in a municipality.

The figures used are averaged from a range of municipalities, which I have undertaken tariff studies for during the past five years.

It is also important to note that this is not a comprehensive COS study. The inaccuracy of the study lies mainly in one aspect, namely that average network costs are used instead of differentiating the costs at the various generic points on the network. That means that the costs of domestic networks, which are much higher than that for large customers supplies, at higher voltages or higher up in the supply network, are understated. This shows that the domestic supply costs are understated.

Table 1 shows the total costs for a typical municipality. The purchase cost, administration and customer service costs are deducted to obtain the network costs only. The last column shows the costs, excluding capital which is to be the minimum for poor customers.

Table 2 shows the calculation of the average network cost per kVA for the whole municipality. This figure should be much higher for domestic networks.

Table 3 shows the calculation of the unit and total cost for domestic customers at various consumption levels.

Whenever these figures are shown, it seems that this is a set of complicated calculations which are incorrect. For this reason, I have also included an alternative calculation method. Table 4 shows the various cost components. It is clear that it yields the same results as the other approach.

Fig. 1 shows the total cost at the various consumption levels.

The following very important observations can be made from this:

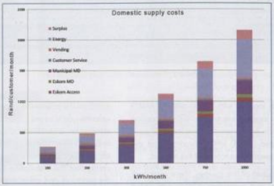

Fig. 1: Total cost at various consumption levels.

Cost of supply 2014/15				
2012/13 finances	General	% of cost	NERSA benchmark	Poor
Purchases	R122 515 157	80,6%	70%	R122 515 157
Salaries and wages	R12 000 000	7,9%	10%	R12 000 000
Maintenance	R3 000 000	2,0%	4%	R3 000 000
Capital charges	R4 500 000	3,0%	6%	
Other	R10 027 303	6,6%	10%	
Total cost	**R152 042 460**	**100,0%**	**100,0%**	**R137 515 157**
Revenue	R182 902 479			
Net income	**R30 860 019**	**16,9%**		

Table 1: Total costs for a typical municipality.

Network costs (general)	General	Units	Poor
System ADMS	30 000	kVA	30 000
Sold ADMS (LV equivalent)	27 273	kVA	27 273
Customer services costs	R8 514 288	Rand/year	R8 514 288
Costs excluding purchases and service	R21 013 015	Rand/year	R6 485 712
Network cost average	R64,21	R/kVA/month	R19,82

Table 2: Calculation of average network cost per kVA for the whole municipality.

- The fixed costs associated with 100 kWh/month are close to R85/month.
- The average price reduces from 171 to 115 c/kWh at 100 vs. 1000 kWh/month.

Based on my experience, I would estimate that the average costs would not differ by more than plus or minus 20% for the different municipalities in South Africa. This gives a good basis to start analysing some of the current practices in municipalities.

Inclining block tariffs (IBT)

The application of IBT has been controversial since it has been forced down by NERSA. The issues relating to process will not be covered here, except to say that NERSA has never answered the questions raised by AMEU/SALGA. Various workshops were set up by NERSA to discuss this, but these were either cancelled or only issues of practical implementation were allowed.

Besides the many concerns with the IBT, the key problems that the industry now faces in respect of IBT, are as follows:

- The fact that the IBT tariff does not cover the operating cost of electricity supply. This means increasing cross-subsidy requirement.

Design of SPU tariff 2014/15					
Domestic characeristics	General			Units	Poor
Annual LF	26%	35%	39%		26%
Average monthly LF	42%	51%	55%		42%
Average usage	100	500	1000	kWh/month	100
Annual MD	0,53	1,96	3,51	kVA	0,53
Average montly MD	0,33	1,34	2,49	kVA	0,33
Installed capacity	20	60	120	A	20
Domestic network cost	R64,21	R64,21	R64,21	R/kVA/month	R19,82
Eskom access	R17,27	R17,27	R17,27	R/kVA/month	R17,27
Eskom demand	R21,85	R21,85	R21,85	R/kVA/month	R21,85
Ratio: Installed Amp/access MD	37,96	30,66	34,16	Ratio	37,96
Ratio: Installed Amp/monthly MD	61,32	44,68	48,18	Ratio	61,32
Total domestic demand/access	R2,50	R3,15	R2,84	Rand/A	R2,50
Eskom energy cost	63,00c	63,00c	63,00c	c/kWh	63,00c
Losses at LV	14%	14%	14%	% purchases	14%
Surplus	15%	15%	15%	% of cost	
Basic cost	R36,00	R36,00	R36,00	R/cust/month	R36,00
Cost reflective charges					
Basic charge	R41,40	R41,40	R41,40	R/cust/month	R36,00
Network charge	R2,44	R2,44	R2,44	R/A/month	R2,50
Energy cost	81,27c	81,27c	81,27c	c/kWh	71,82c
Cost reflective revenue					
Basic charge	R41,40	R41,40	R41,40	R/cust/month	R36,00
Network cost	R48,74	R146,23	R292,45	R/cust/month	R50,05
Energy cost	81,27c	81,27c	81,27c	c/kWh	71,82c
Total energy cost	R81,27	R406,35	R812,70	R/cust/month	R71,82
Total cost	R171,4	R594,0	R1146,6	R/cust/month	R157,9
Average cost	171,4c	118,8c	1147,7c	c/kWh	157,9c

Table 3: Calculation of unit and total cost for domestic customers.

Domestic cost summary						
kWh/month	100	200	300	500	750	1000
Eskom access	R9,10	R16,32	R22,18	R33,80	R47,95	R60,66
Eskom MD	R7,13	R13,30	R18,71	R29,34	R42,36	R54,42
Municipal MD	R33,83	R60,66	R82,46	R125,65	R178,29	R225,52
Customer services	R16,00	R16,00	R16,00	R16,00	R16,00	R16,00
Vending	R20,00	R20,00	R20,00	R20,00	R20,00	R20,00
Energy	R63,00	R126,00	R189,00	R315,00	R472,50	R630,00
Surplus	R22,36	R37,84	R52,25	R80,97	R116,56	R150,99
Total	**R171,41**	**R290,12**	**R400,59**	**R620,76**	**R893,66**	**R1157,60**

Table 4: Various cost components.

- The on-going low increases for the first blocks, below the Eskom/average price increases.
- The emergence of renewable energy and the eroding of the municipal revenue base from high users.
- The practical problems associated with IBT are on both conventional and pre-paid.

Negative financial impact

NERSA recently sent out a questionnaire where the status of IBT implementation is requested. One of the leading questions is what successes have been achieved with IBT and what the revenue impact was. These impacts should now be known and hopefully NERSA will make these available to the industry.

The negative impact on some of the municipalities are extreme:

- Municipality A in Gauteng, lost R53-million with the introduction of IBT tariffs. Four years later this municipality now owes Eskom close to R200-million.
- Municipality B in the Free State lost R75-million due to the implementation of IBT.
- Municipality C in Eastern Cape will lose R15,5-million, close to 14% of total revenue, which will wipe out the total surplus income on electricity.
- A small municipality in the Western Cape will lose R8,6-million or 16% of total revenue and wipe out any surplus income.

Despite the massive reduction in charges to poor customers, non-payment is growing at an even faster rate. All it has caused is a non-appreciation for a very scarce resource and on-going increased usage.

The losses incurred have either put municipalities in a very serious financial shortfall situation, or the brunt of the burden has been placed on large customers. It must be understood that this burden is showing its impact in many ways such as:

- Mines not being able to pay their workers properly
- Factories and businesses closing down and jobs being lost

Cost vs. revenue

The reasons for a lot of the revenue losses are because municipalities were applying tariffs that are closer to cost reflective than the IBT. I will illustrate this by comparing it with the COS study results. Remember that these are the most conservative figures possible. In the real situation the costs would be much more. This is shown graphically in Fig. 2.

The following observations can be made from this comparison:

- At 100 kWh/month the shortfall is R101 per customer per month and at 350 kWh/month it is R70/month.
- Customers with 40 A circuit breakers typically use less than 600 kWh/month and no surplus is made from these customers
- Customers with 80 A circuit breakers will break even with cost close to 900 kWh/month.

To understand the impact of these tariffs, we need to know how many customers are using at the different consumption levels. The table below shows the situation for a typical municipality.

The following can be concluded from this in respect of the financial impact:

- 56 520 customers use 350 kWh/month or less and are subsidised by on average R80 per month which is equal to R4,5-million.
- There are 3982 customers which use more than 900 kWh/month. They would need to be overcharged by R1135 per month each, to make up for the shortfall.

This would be close to a 100% overcharge. Surely this is not sustainable.

An even bigger concern relates to the fact that these shortfalls are going to increase over time because of the following:

- The number of poor (low usage) customers are increasing.
- The tariff increase allowed by NERSA on the first IBT blocks are below the average cost increases.

Domestic tariff												
		Basic	Capacity	Energy								
Tariff	Capacity	Per month	Per kVA (installed)	Block 1 rate	Block 1 kWh	Block 2 rate	Block 2 kWh	Block 3 rate	Block 3 kWh	Block 4 rate		
	A	R/m	R/kVA/m	c/kWh	kWh/m	c/kWh	kWh/m	c/kWh	kWh/m	c/kWh		
Cost 2014/15	20	R41,40	R13,51	81,27	All							
Cost 2014/15	40	R41,40	R16,65	81,27	All							
Cost 2014/15	80	R41,40	R15,33	81,27	All							
IBT 2014/15	20			74,00	50,00	93,00	350,00	126,00	600,00	148,00		
Revenue												
	kWh/m	0	100	200	300	400	500	600	700	800	900	1000
20	Cost 2014/15	R101	R183	R264	R345	R427	R508	R589	R670	R752	R833	R914
40	Cost 2014/15	R189	R271	R352	R433	R514	R596	R677	R758	R840	R921	R1002
80	Cost 2014/15	R314	R395	R476	R558	R639	R720	R802	R883	R964	R1045	R1127
20	IBT 2014/15	R0	R84	R177	R270	R379	R505	R631	R779	R927	R1075	R1223

Table 5: Costs vs. tariffs.

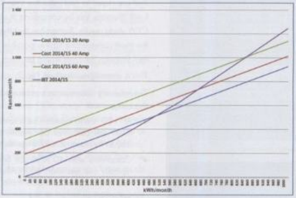

Fig. 2: Domestic revenue vs. cost.

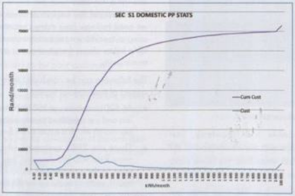

Fig. 3: SEC S1 domestic PP stats.

This means that the cross-subsidy impact is continuing to increase exponentially and unsustainably.

Compliance with LGMSA

Local government is governed inter alia by the Local Government Municipal Systems Act of 2000 which makes the following stipulations:

In the introduction:

"Ensure that municipalities put in place service tariffs and credit control policies that take their needs into account"

"(2) A tariff policy must reflect at least the following principles, namely that:

Poor households must have access to at least basic services through:

(i) tariffs that cover only operating and maintenance costs;

(d) tariffs must reflect the costs reasonably associated with rendering the service, including capital, operating, maintenance, administration and replacement costs, and interest charges;

Tariffs must be set at levels that facilitate the financial sustainability of the service, taking into account subsidisation from sources other than the service.

(i) the extent of subsidisation of tariffs for poor households and other categories of users should be fully disclosed.

(h) The economical, efficient and effective use of resources, the recycling of waste, and other appropriate environmental objectives must be encouraged."

The question that needs to be answered is whether the current tariffs being enforced by NERSA, applies with the legal requirements. This will be tested below:

- In respect of points (i) and (d). Table 3 shows that the average cost (excluding capital) of a poor customer using 100 kWh/m with a 20 A CB is 157 c/kWh. This is more than double the NERSA IBT first block and 70% more than the second block.
- In respect of point (i). With the IBT tariff it is very difficult to quantify the subsidies as there are no cost reflective tariffs in place to compare it with. None of the NERSA documents even request this.
- Because the energy price for the high IBT block at 148 c/kWh is more than double the energy cost at 63 c/kWh, inefficient energy usage is encouraged and customers are moving to alternatives when electricity should still be used.

Renewable energy

The emergence of affordable renewable energy sources are beginning to make big

	Measure	kWh	MD
1	LED/efficient lights	100%	100%
2	Solar water geysers	100%	70%
3	PV systems	100%	10%
4	Gas for cooking	100%	100%
5	Gas for space heating	100%	80%
6	General awareness	100%	80%

Table 6: Profile impact of efficiency measures.

inrushes in South Africa. People are beginning to undertake many actions to reduce their electricity consumption.

This trend for more efficient use is welcomed and must be encouraged. The problem is that the municipal revenue base is being eroded by far more than the cost savings, which is causing a financial squeeze.

Each of these measures has an impact on the consumption level and on the maximum demand (MD) of the municipality. The impact of each is shown in Table 6.

All of these will impact the kWh used to the full extent of the efficiency impact. The impact on system MD is however very different for each:

Efficient lights

The lights are used to some extent during the early hours of the day, where it has a very small impact on system MD, or largely in the evening, where it will have a full impact on the system MD.

Solar water geysers

These will have a significant impact on reducing the MD on the system during the morning and evening system MD.

- Provided the system is set up for the element not to be on during these times. The general advise should be to boost the system with electricity:
  - From 04h00 to 06h00 before system demand starts climbing and then there will be hot water for morning activities.
  - From 16h00 to 18h00 before the system starts going into its highest peak. These times should be adjusted between summer and winter.
- If the systems are not set up like this, it could impact the system MD negatively.
  - If the element comes on from 18h00 to 20h00, which by the way is the ideal from a total kWh usage perspective, because then the sun is fully set.
  - This could even cause the MD to be higher than when a normal geyser is used during a cloudy day.

PV systems

The PV systems mostly installed are without battery storage and thus will only impact electricity profile while generating. PV systems will reduce the demand, based on the typical profile of a PV system, which is illustrated in Fig. 4.

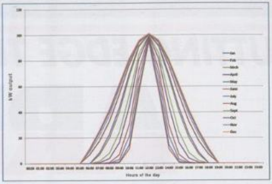

Fig. 4: kW out of 100 kW PV system in Cape Town.

It is important to note that this applies to most of the country, but in the Western Cape, the output will be on average up to one hour earlier. This means that with the evening peaks (18h00 to 20h00), the impact will be minimum, except for the three summer months in the Western Cape, where less than 20% of demand will be impacted. We can thus conclude that PV systems will in itself have a minimal impact on system evening peak demand. If customers move some of their loads to the daytime to maximise the usage of the PV system, the system peak demand would be reduced.

The real problem comes on very cloudy days when it is mostly also cold, the PV system output will be reduced significantly, thus requiring the customers to make full use of grid electricity. The customers can thus also not reduce their own circuit breaker sizes significantly, if they want to avoid being without electricity during these critical days.

The conclusion is that PV systems will not reduce the system peak MD significantly and also not the customer's required circuit breaker capacity. This is more a reality in the Western Cape, when due to the rainy season, have a lot of cloudy days.

Gas for cooking

Using gas for cooking is very good for the electricity system, because it reduces the system MD more than it impacts the kWh used. This happens because it is largely used during the system peak times (18h00 to 20h00).

Gas for space heating

When customers use alternatives for space heating, including gas, it is very good for the system. The typical annual load factor for space heating is less than 4% (three months for four hours per day). At least two of these hours are during the system peak times. This should thus be welcomed by utilities, provided the tariffs are set correctly.

General awareness

General awareness should impact the kWh and system impact to a similar extent, except when the customers experience an extreme cold spell or having a big function at home. This may result in people to ignore all savings and fall back into old habits and thus not reducing the system MD.

The impact of reducing kWh and reducing MD is shown in Table 7.

EE impact	Lights	Solar	PV	Cooking	Heating	Awareness	Totals
kWh reduction	150	300	500	150	155	50	1305
MD reduction kW	0,20	0,20	-	1,20	2,00	0,17	
Eskom access	R3,45	R3,45	-	R20,72	R34,54	R2,96	
Eskom MD	R4,37	R4,37	-	R26,22	R43,70	R3,75	
Municipal MD	R12,84	R12,84	-	R77,05	R128,41	R11,01	
Customer service	-	-	-	-	-	-	
Vending	-	-	-	-	-	-	
Energy	R121,91	R243,81	R406,35	R121,91	R125,97	R40,64	
Surplus	R21,39	R39,67	R60,95	R36,88	R49,89	R8,75	
Total	**R163,96**	**R304,15**	**R467,30**	**R282,78**	**R382,51**	**R67,10**	
Revenue IBT	R222,00	R444,00	R740,00	R222,00	R229,40	R74,00	
Revenue COS	R124,10	R246,00	R406,35	R135,07	R147,90	R42,52	
Net impact							
IBT tariff	R(58,04)	R(139,85)	R(272,70)	R60,78	R153,11	R(6,90)	R(263,60)
COS tariff	R39,86	R58,14	R60,95	R147,72	R234,61	R24,59	R565,87

Table 7: Load reduction impact.

The following should also be considered in this respect:

- In Table 7, the effect that the energy cost is more expensive during peaks and especially during high demand period, has not even been considered. This will make the impact of lights, cooking and especially space heating, much better.
- It has been assumed that if customers introduce these measures and at the same time downgrade their circuit breaker sizes. If they do not, the COS tariff option will look even better.

The following can be concluded from this:

- The big reason why the introduction of renewable energy will be negative is because of the application of the IBT tariffs and thus the very high prices for marginal sales (the highest of units per month).
- The negative impact can totally be overcome, and in fact be turned into a positive impact, if COS tariffs are applied.
- In cases where power is injected into the system from PV systems, a further benefit can be enjoyed by the municipality provided:
  - The COS tariffs are applied
  - Energy is purchased from the customer in TOU basis equal to the Eskom energy charges, plus levies
- When a customer's consumption reduces, they will eventually move to the scenario where they will not contribute to the cross subsidies, but will not even cover their own costs. NERSA's whole cross subsidy plan will thus not succeed.

Large customer cost of supply

A simplified cost of supply (COS) study is done here as a basis for the analysis of large customer tariffs. Table 8 shows a simplified COS study for large customers.

Table 9 continues this analysis by adding the surplus and losses and comparing the cost with current charges. A fact that has a major impact on the results of these analysis, relate to how the Eskom MD and access charges are applied as either:

- An access charge or MD charge to customers
- As part of the energy cost as a c/kWh charge

The method used here, is to use it as applied to the municipality and thus expose customers to the same signals. This is the recommended method.

The following can be said in this respect:

- The energy charge is less than cost
- The demand charge is by far overstated
- The total revenue exceeds the cost, plus a surplus of 16% by a further 17%

It is thus clear that large customers cross

Network costs (general)	Full cost	Units		
System ADMD	30 000	kVA		
Sold ADMD (LV equivalent)	27 273	kVA		
Customer service costs	R8 514 288	Rand/y		
Costs excluding purchases and service	R21 013 015	Rand/y		
Network cost average	R64,21	R/kVA/m		
Large customer analysis			**Access**	**Demand**
Average MD network cost	R64,21	R/kVA/m	R25,68	R32,10
Eskom MD charge	R21,85	R/kVA/m		R21,85
Eskom access charges	R17,27	R/kVA/m	R17,27	
Total large customer demand costs	R103,32	R/kVA/m	R42,95	R53,95
LPU co-insidence factor of MD	65%			
Total LPU MD cost	**R72,53**	**R/kVA/m**	**R30,15**	**R37,87**

Table 8: Simplified COS study for large customers.

	Demand	Energy
	R/kVA/month	**c/kWh**
Current charge	R181,38	59,49c
	Access/MD	**Energy**
Cost	R72,53	56,74c
Losses	8%	8%
Surplus	17%	17%
Cost	R90,57	70,85c
Differences	**Overcharge**	**Undercharge**
	100,3%	-16,0%
Large customer characteristics	Ave LF	45,0%
Ave price at cost	c/kWh	98,42c
Ave price at tariff	c/kWh	114,70c
Overcharge	c/kWh	16,28c
Overcharge	%	17%

Table 9: Large customer analysis at MV for 2014/2015.

subsidise domestic customers, especially at low usage.

Large customer time of use

The next issue that needs debate is the time of use (TOU) tariffs for large customers. The EPP stipulates the following on this issue in December 2008 (6 years ago):

Policy position: 31

Tariffs must include TOU energy rates as follows:

- *all customers supplied at MV or above within two years;*
- *all customers above 100 kVA within five years;*
- *all cases where the metering provides such features withing five years; and*
- *all other customers where it is warranted.*

Many municipalities have progressed far in this respect and more and more TOU meters are being installed for large customers. These meters are expensive and many municipalities have taken the route of providing communications to the meters, which makes sense, but is even more costly.

I want to address the problem of tariff structure and levels. Based on years of experience, the following is proposed for the design of the TOU tariffs, which is very similar to the Eskom Megaflex (MF) tariff:

Basic charge

This is applicable per point of supply and should be as close as possible to the customer's services costs including the cost of metering. It should be differentiated by:

- Customers supplied at low voltage (LV)
- Customers supplied at medium voltage (MV) 6,6 kV to 22 kV. This charge should be higher, because more attention is given to these customers and a more expensive metering installation, which includes a VC/CT unit and in some cases a dedicated ring main unit or T-switch.

TOU periods

The seasons and time of day periods should be similar to that of Eskom even if the local peaks are different from the Eskom peak periods.

Access charge

An access charge should be applied to cover the dedicated part of the network cost and the Eskom access charges.

It should be based on the highest of the notified demand or the previous 12 months highest demand.

Maximum demand (MD) charges

A maximum demand charge should be retained, but only applicable in the peak and standard times. It is to cover the rest of the

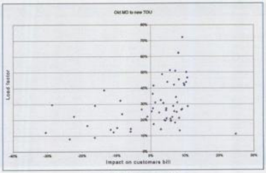

Fig. 5: Old MD to new TOU.

network cost and Eskom MD charges, and be as close to cost as possible.

Active energy charges

The energy rates should be set equal to:

- The Eskom TOU energy rates (the basic rates plus the c/kWh and all the other Eskom c/kWh levies)
- Plus a fixed c/kWh mark-up. This ensures that when customers shift load to cheaper energy periods, the municipality does not lose any money by incurring a savings in Eskom purchase cost equal to the reduction in revenue.
- The c/kWh should be set by undertaking an impact study for as many as possible of the large customers involved and ensuring that the revenue on the new MD tariffs equal that on the new TOU tariffs.

Reactive energy charges

These should be applied similar to Eskom, to also provide a signal for customers to control their power factor during all peak and standard periods, even if it is not during their own system peaks. In the absence of a study in this respect, a charge similar to Eskom is proposed.

Differentiation between MV and LV customers

These need to be set equal to that found in a COS supply study. In the absence of this, the same percentages for the maximum demand tariffs can be applied, but this should be close to 5% higher on energy and at least 10% higher on demand for LV customers. This should be applied to the access charges, MD charges, and the active energy rates.

Public holidays

These should be treated as follows:

- The same as Eskom in cases where the meters are equipped with remote communications and can be programmed remotely.
- As normal week or weekend days with no alteration. The tariff rates must be set to ensure fair compensation. This is to avoid the onsite reprogramming of the meters annually.

An example of such an impact study is shown in Fig. 5. It shows the annual impact of all the MV customers in a municipality.

Although it looks like many customers will be less, the average impact was equal to the average increase of 7,39% required by the municipality. The reasons for higher and lower payments are as follows:

- Higher load factors (LF): generally increase more than average
- Very high MD for only few months: generally have higher than average increase
- Extensive usage during peak times: generally have higher than average increase
- All customers: Big increase for June, July, August and a very small change in other months

Average price increase	
	NERSA guideline
Cost line item	Percentage of municipality cost
Purchases	70,0%
Salaries and wages	10,0%
Maintenance	6,0%
Capital charges	4,0%
Other	10,0%
Surplus	20,0%
Total revenue	**120,0%**
Revenue markup on purchases	71,4%
Selling price/Purchase price	**1,71**

Table 10: Effective mark-up on Eskom tariff when applying NERSA guidelines.

The only way recommended for implementation, is to do all large customers on an involuntary basis.

First the MV customers, then the other large customers which can be phased in those with MD > 200 kVA, then > 100 kVA and then the rest.

The reason for this is to ensure that the municipality's revenue base is not eroded, due to only those customers paying less when converting.

This will ensure that the current level of cross subsidisation by large customers is retained, but at least not increased and allowing them to reduce their bills through load shifting.

NERSA TOU tariffs

The biggest problem starts when the required analysis has been done and you apply to NERSA for approval. NERSA has a standard that says TOU tariff must be equal to Eskom plus 20%. NERSA was challenged on this basis, but no reply was ever received.

Table 10 shows the effective mark-up on the Eskom tariff when applying the NERSA guidelines.

This shows that if the NERSA benchmarks are used as a basis, an average mark-up of 71% should be allowed on the purchase price. Furthermore it shows that the ratio of selling price to purchase price should be 1,71 compared with its own benchmark of 1,6.

In assessing this figure the following should be recognised:

- If tariffs were cost reflective, the mark-up for large customers should be lower than for small customers due to the lower cost.
- With the massive cross subsidies to domestic customers, largely because of NERSA's IBT tariffs, large customers have to pay more than cost, thus requiring a higher mark-up.

This first section shows that a mark-up of 20% does not align with NERSA's other benchmarks. There is great sympathy and agreement with NERSA's strategy to reduce the overcharging of large customers. It can however not be done in the way they propose because:

- It is only enforced for new TOU tariffs. This means that existing serious discrimination of 85% mark-up is unaffected in any of the NERSA strategies.
- This means that municipalities simply cannot apply the new TOU tariffs at the Nersa levels, because they will lose too much revenue which means TOU is not progressing.
- If it is NERSA's strategy to reduce the overcharge of large customers a proper strategy much be developed which must:
  - set target reduction of tariff levels for the large customers paying the subsidies

TOU charges	High			Low		
	High: Peak	High: Standard	High: Off-Peak	Low: Peak	Low: Standard	Low: Off-Peak
Eskom MF MV (c/kWh)	211,54c	67,87c	39,33c	72,66c	51,70c	34,78c
Proposed TOU (c/kWh)	227,53c	83,86c	55,32c	88,65c	67,69c	50,77c
% markup	8%	24%	41%	22%	31%	46%
c/kWh mark-up (c/kWh)	15,99c	15,99	15,99	15,99	15,99	15,99
Fixed % mark-up (c/kWh)	48,33c	15,51c	8,99c	16,60c	11,81c	7,95c
Load shift impact	Peak to off-peak	Peak - standard	Standard - off-peak	Peak to off-peak	Peak - standard	Standard - off-peak
c/kWh mark-up (%)	0%	0%	0%	0%	0%-	0%-
% mark-up (%)	39,34%	32,82%	6,52%	8,65%	4,79%	3,87%
% Loss	19%	48%	17%	12%	9%	11%

Table 11: Affect of NERSA TOU tariffs.

- and target increase of tariffs for the domestic customers receiving the subsidies
- with a phase in plan.

Another problem with the way in which NERSA is applying the benchmark, is that it is proposing the same percentage mark-up be applied on all the Eskom rates. This is a major problem and will cause massive distortions from cost reflective, because of the following:

- If the same percentage mark-up is applied to the Eskom rates, a major distortion will take place and the tariff will not be cost reflective. This is because the mark-up on the Eskom network costs, should be a much higher percentage to cover all the municipal network cost, typically more than 100% mark-up.
- If a fixed percentage mark-up is applied to the energy rates, the c/kWh mark-up on the most expensive rates would be as much as four times more than on the cheaper rates. This means that when customers shift load from the expensive, to the cheaper time, as it is one of the objectives, the municipality will lose much more revenue than the savings in Eskom bill and thus net revenue. This is illustrated in Table 11. The mark-up should be based on cost and energy mark-up should ideally be in c/kWh except in case of losses.

NERSA should thus rather develop a proper basis to determine benchmarks for municipal TOU tariffs.

Conclusions

It is clear that the industry is facing serious challenges from a tariff point of view:

- IBT tariffs that are applied are causing on-going escalating cross-subsidies, causing lost revenue and both of these are not sustainable and are impractical.
- If TOU tariffs for large customers are set according to the NERSA benchmark, municipalities will lose revenue when customers convert to TOU and when customers shift load to the cheaper periods.

The challenge that NERSA faces when municipalities do not provide adequate information and submit their tariff applications late is recognised. This will contribute to NERSA having to make hasty decisions, without allowing adequate time to analyse the municipal proposals and get into meaningful debate with the municipalities.

On the other hand however, there have been many incidents where such opportunities did exist and NERSA has been unmoveable, despite sound arguments being made.

Where to from here

In view of these problems the following processes is proposed for municipalities:

- Municipalities must develop tariffs which comply with the EPP.
- These tariffs must also comply with the MFMA.
- Tariff applications need to be made to NERSA in time.
- Municipalities must not accept approvals which do not take their needs into account and appeal the NERSA decision.
- NERSA must develop benchmarks that have been properly analysed and consulted on.
- NERSA must negotiate with municipalities as they know their local circumstances best.

Municipalities are thus encouraged to do the following in terms of tariffs:

- Apply cost reflective charges for all their small customers with a basic charge, and Amp charge and energy charges (possibly seasonally differentiated)
- Make available a life line tariff with a single energy rate, restricted to 20 A maximum, which equals the operating cost.
- Large customer TOU tariffs must be based on cost and must initially ensure revenue neutrality, with existing tariffs, with energy rates, with a fixed c/kWh surcharge.
- If large customer cross subsidies are to be reduced, it needs to be targeted as a specific strategy and it must be clear to everyone and not hidden behind a TOU tariff.

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Are lower prices an illusion or reality in a deregulated market?

by Angelo Carolus and Aldene Nelson, SAP ISU and Nathi Mhlongo, Zimele Technologies

The South African energy market has been solely managed by utility company Eskom, accounting for generating, transmitting and, in other cases, supplying and distributing energy countrywide.

With this in mind, the South African energy market has the prospect of embarking on deregulating the current energy market, allowing for both local and foreign investment, forming a more viable solution to the energy crisis at hand.

In light of this fact, this paper intends to address the issue of a competitive energy market, and the consequent effect thereof.

The current South African energy outlook

"President Zuma's call for a radical transformation in South Africa's energy sector in his State of the Nation Address hit at the core of the country's energy catastrophe. Without energy, the National Development Plan (NDP) and all plans for growth are dead in the water, along with prospects for jobs. South Africa has an immediate and future energy crisis. We need a radical policy to secure affordable and reliable energy to solve the short-term emergency and the long-term supply to power essential GDP growth." [1]

The National Development Plant (NDP) iterates that the economy urgently needs increased competition in electricity generation, that gas should be explored and new generation capacity should be divided between Eskom and Independent Power Producers (IPP):

"Economic growth and development through adequate investment in energy infrastructure and the provision of quality energy services that are competitively priced, reliable and efficient. Local production of energy technology will support job creation." [2]

What are the consequences if South Africa continues with a regulated market?

"Eskom Energy Generation Company has been at the heart of the South African energy market, generating approximately 95% of the electricity used in South Africa and a significant 45% of the electricity used in Africa. Eskom generates, transmits and distributes electricity to industrial, mining, commercial, agricultural and residential customers and redistributors." [3]

Many factors, including "load shedding", pressure authorities to devise more than one energy producer and transmission company. Therefore if no alternative to Eskom is established to enter the market and compete, the track record of Eskom will decline, resulting in South Africa relinquishing foreign trade investment opportunities. The consequences of continuing with a regulated market leads to increased theft, poor revenue collection and increased energy tariffs.

Rapid progress and partnerships must be established with IPPs, ensuring that the demand on the electricity grid is sustained. In the past, one out of every three South Africans had access to electricity. Currently, over 80% of the population has access to power. This rapid growth will impact the state-owned utility, resulting in poor domestic and commercial services, support and infrastructure. This alarming issue is evident in today's climate of vandalism and destruction of property by end-users experiencing high tariff increases and load shedding.

Standard Average Price and percentage price increases	2010/2011	2011/2012	2012/2013
Standard Average price (c/kWh)	41.57 c/kWh	52.30 c/kWh	65.85 c/kWh
Percentage Price Increase	24.8%	25.8%	25.9%

Fig. 1: No intervention (proposed increase).

Standard Average Price and percentage price increases	2010/2011	2011/2012	2012/2013
Standard Average price (c/kWh)	41.57 c/kWh	52.30 c/kWh	60.57 c/kWh
Percentage Price Increase	24.8%	25.8%	16%

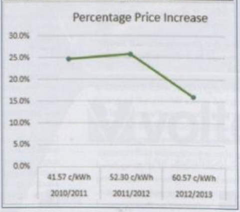

Fig. 2: Government intervention (new increase).

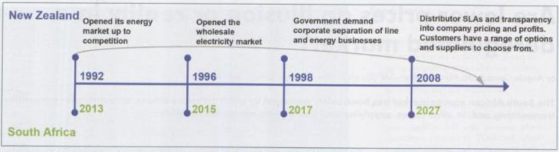

Fig. 3: Based on the above study and timeline, South Africa might meet the set target of the NDP for 2030, with the introduction of IPPs and alternative energy sources.

Are lower prices an illusion or a reality in a de-regulated environment?

In retrospect, telecommunication giant Telkom, being the only communications company for decades, with no competitors, required drastic deregulation as the communication company could not sustain the demands of the market timeously. With the correct market competitors and stimulation, consumers now have a wide range of products and service providers to choose from, resulting in a more conclusive communication network and increased customer satisfaction, to mention a few.

Transparency concerns raised in the deregulation of telecommunication company Telkoms included:

- How can end-users really check what a particular phone call costs?
- How many minutes have they actually used when the statement arrives more than 30 days later?
- What are set-up costs or kick-back rates – and what is breakage?

Similar transparency concerns could relate to Eskom:

- How can Eskom provide key customer service across South Africa in an effective and conclusive manner?
- Transparency relating to costs involved with maintenance call-outs, new installations, if no alternative exists for pricing comparison.

What are the consequences if South Africa moves to a deregulated market?

A reliable energy market, which is competitive in pricing and service delivery, will be one of the major driving factors for the success of the NDP. The average household will be able to choose between competitive energy suppliers, resulting in more manageable tariff increases. The consequent factors of a deregulated market have far reaching beneficial impacting factors, i.e. increased revenue protection, job creation, sustainability and increased productivity.

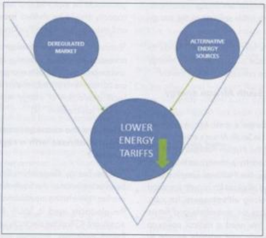

Fig. 4: A fully deregulated market, supported with alternative sources of energy, will be a driving force in lowering costs of electricity.

Some noticeable benefits experienced by other countries positioned similarly to South Africa

Regulators will no longer be allowed to determine which firms will be given the privilege to serve consumers via exclusive franchising arrangements and other barriers to entry.

- Lower prices for residential users by empowering them to choose their electricity supplier.
- Direct competition posed by new firms entering the market would also develop higher quality of service and innovation within the industry.
- Competition among firms will lead to organisations being more responsive to user demands.
- Deregulation means empowering the end-user with options and ultimately trust in the service product.
- Collectively, commercial users especially small power users, stand to benefit a large percentage of overall monthly costs allocated to utility bills, in particular electricity. The most cost-effective service provider will be chosen, within these smaller organisations, ensuring sustainability.

Tariffs increases in South Africa

The cost of electricity will most definitely change, based on other use case studies across the world. The impact of deregulating the energy market results in most benefits realised. Tariff increases within a regulated market will always be a challenge, experienced by most countries.

"The 2012/13 tariffs are NERSA approved rates as per the 9 March 2012 NERSA decision on electricity tariff increases averaging 16%, which is lower than the 25,9% originally approved by NERSA. The 2012/13 tariffs are effective as of 1 April 2012 for non-local authorities and 1 July 2012 for local-authorities." [4]

Multi-year price determination (MYPD3)

The lower electricity price increases are the result of a combined effort by government and Eskom to lessen the impact of higher electricity tariffs on consumers and the economy in the short term without compromising Eskom's ability to keep the lights on and ensure its long-term goal for financial sustainability. If this has not occurred, the result would be that many South Africans will be faced with the reality of not being able to afford electricity.

In the future, this type of intervention displayed by government might be driven by clients, forcing Eskom or competing firms to lower or decrease tariff increases, largely attributed to competitiveness within a synergised market.

The New Zealand deregulated case study

- *1992:* New Zealand officially opened its energy market up to competition – converted local power distributors into individual companies.

  The driving factor and roots for New Zealand's deregulation trace back to the mid-1980s when concerns grew over the country's economy; the proposed way forward was the efficient management of resources and a more transparent market.

  The government's ministry of energy ran New Zealand's electricity generation and transmission, pricing and investments driven by politics. Operations were plagued by inefficiencies and lack of end-user choice.
- *1996:* New Zealand opened the wholesale electricity market officially with a state-owned company Contact Energy, being in direct competition with the Electricity Corporation of New Zealand.

  This resulted in a major breakthrough with generators, purchasers and traders being able to set the market electricity prices.
- *1998:* Government demands corporate separation of line and energy businesses, preventing cross-subsidies and monopolies of local distribution networks.
- *2008:* Ten years later, distributor SLAs and transparency in terms of company pricing and profits bought customers a range of options and suppliers to choose from.

Based on the study and timeline in Fig. 3, South Africa might meet the set target of the NDP for 2030, with the introduction of IPPs and alternative energy sources.

Conclusion

South Africa as a country requires some rigorous market transformation, ensuring longevity and growth. The introduction of IPPs and alternative energy sources will assist in driving down the cost of energy. The envisioned competitive market will bring about much innovation and initiatives for saving or reducing energy usage. Paramount to reducing South Africa's carbon footprint is the introduction of alternative renewable energy sources.

The deregulation of the energy market similar to that of New Zealand, where transmission lines or generating power for the same grid are shared, will result in a competitive and resilient market for all parties involved.

This competitiveness, as seen in the New Zealand market, will bring about the much needed makeover, and pricing will decline for previously regulated "regular tariff increases". Therefore, lower prices are not merely an illusion but in fact a true manifestation as experienced by other countries in a deregulated market.

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Small scale on-grid PV embedded generation methodologies in South Africa

by Paul Tuson, Mott MacDonald

The IRP 2010-30 update [2] states that 9770 MW of solar photovoltaic (PV) capacity is planned to be installed in South Africa by 2030.

The update also estimates that embedded generation (EG) residential and commercial PV could reach 22,5 GW by 2030 based on living standards measure 7 (LSM 7) households and 5 kW PV household installations [2]. Even if this estimate is partially correct, this points to a significant level of installed small-scale solar PV embedded generation (SSPVEG) capacity in South Africa by 2030.

The AMEU guideline on embedded generation [3] states that the following PV market uptake is projected for Johannesburg over the next ten years:

- Approximately 45 000 PV systems in the residential market
- Approximately 4000 PV systems in the commercial market
- Approximately 670 PV systems in the industrial market

The AMEU guideline on EG [3] reports that Municipalities and Eskom are being inundated with applications from customers to allow them to install some kind of grid connected embedded generation [3].

This shows that interest in small scale solar PV EG (SSPVEG) is growing and that SSPVEG installations are currently occurring in South Africa, with or without a national SSPVEG framework.

There is an obvious attraction to on-grid residential solar PV installations as the cost of solar PV systems decrease [1, 2, 3, 7], the cost of utility electricity increases [2, 3], Eskom's reserve margin reduces [2], and environmental and sustainability awareness among electricity users increases [3]. EGs in the form of residential or commercial solar PV can also derive income when their generated electricity exceeds their load and they export their surplus electricity to the grid.

Besides the high SSPVEG projections and growing installations, there is a level of frustration in the renewable energy (RE) industry [3, 8] that not enough is being done to encourage SSPVEG in South Africa and that in fact there are real obstacles to the growth of the solar PV EG industry in South Africa. Some of these obstacles are perceived to be as follows:

- Decrease in municipality revenue base. Up to 70% of municipal income is derived from electricity sales in some cases [3, 7, 8].
- Reduced ability for municipalities to cross-subsidise other municipal services using electricity revenue [3].
- Risk of LV and MV system overloading from high simultaneous solar PV EG generation into the local grid at for example midday [3, 5].
- Safety of utility personnel [3, 5, 9].
- Lack of pre-approved, generic standards for the solar PV EG/utility interface [3, 5].
- Regulatory and legal obstacles [3].
- Quality of supply (QOS) impact of PV equipment [3].

This paper attempts to address decreased municipal revenues. It focuses predominantly on on-grid or parallel-connected SSPVEG (as opposed to off-grid and other RE technologies) at a residential and small commercial level and attempts to find pragmatic and sustainable solutions to SSPVEG roll-out in South Africa. SSPVEG with battery or other storage is not addressed in this paper.

The current situation

Several standards, grid codes, guidelines and acts are being developed or exist in South Africa, intended to regulate the planning and implementation of RE generation and SSPVEG in South Africa.

There is not enough space in this paper to discuss the main technical, legal and regulatory elements in all these documents, but certainly they have a major impact on the SSPVEG landscape in South Africa which will be referred to in the document.

The draft NRS097-2-1 standard proposes the following small-scale EG categories (in line with the renewable power plant grid code [13]:

Category A1: 0 to 13,8 kVA

Category A2: 13,8 to 100 kVA

Category A3: 100 kVA to 1 MVA

Most residential consumers are currently installing small-scale solar PV EG systems [4, 5, 9] in the A1 category and most commercial consumers are currently installing SSPVEG systems in the A2 and A3 categories even in the absence of finalised SSPVEG regulations and legislation being in place.

From a legal/regulatory perspective, any entity wanting to "sell" electricity to another entity requires a generation license from NERSA [22]. While generating licenses are not difficult to obtain if the explicit allocation for that energy is not detailed in the NIRP [1, 2], it is possible that NERSA may not identify a specific allocation to rooftop PV installations. This could be a potential blockage for approval of such a license for EGs. However, the Municipal Structures Act 1998, Section 84 (1)

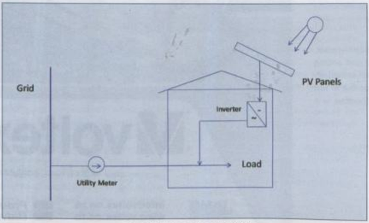

Fig. 1: Self-consumption solar PV EG.

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page 32 [23] states that "A district municipality has the following powers: Bulk supply of electricity which includes for the purposes of such supply, the transmission, distribution and, where applicable, the generation of electricity" [2, 3]. It could be argued that there are already precedents to municipal generation e.g. the purchase of Kelvin Power Station power by City Power in Johannesburg and the Renewable Energy Independent Power Producer (REIPP) programme [1] where electricity is purchased from IPPs and sold on to municipal customers.

From a technical point of view, prevailing residential and commercial meter technologies comprise the older electromechanical technology (rotating disc), newer digital meters and pre-paid meters. Bi-directional metering systems are not currently installed in normal residential and commercial points of supply (PoS) but are being investigated in the draft NRS097-2-1 standard [5].

Currently, most SSPVEGs or prosumers [7, 12] especially in the A1 and A2 categories are not compensated for surplus or export power to their connected utility [3, 8]. In addition, existing SSPVEG installations are taking place in the absence of a coherent regulatory and legal environment [3, 4].

In the following sections the author explores a number of SSPVEG methodologies and tariff mechanisms together with their advantages and disadvantages.

SSPVEG mechanisms

Solution 1 – Self-consumption

In the self-consumption mechanism, solar PV electricity is self-consumed during the day by the residential or commercial consumer as shown in Fig. 1.

The SSPVEG installation is conservatively sized to supply a portion of the prosumer load only and not with the intention to export electricity to the grid. Where SSPVEG generation does exceed prosumer load, the prosumer is not reimbursed and is content to supply the grid with electricity without being financially compensated.

NRS097-2-3 [6] recommends simplified connection rules as follows: "an individual [EG connection] limit of 25% of NMD will typically support a penetration level (percentage of customers that install a generator) of 30% to 50%, which is considered a reasonable and acceptable compromise between restricting individual generator sizes versus restricting penetration levels" [6]. "The NMD in many cases is determined by the LV service connection circuit-breaker rating" [6]. This approach simplifies the after diversity maximum demand (ADMD) system overloading risks mentioned in the introduction above, and allows more freedom for SSPVEGs to connect to the grid without lengthy system analysis and approval processes.

In the above arrangement, the prosumer notifies the municipality or connected utility that he has installed solar PV for self-consumption purposes. Notification procedures could align with certificate of compliance and application for inspection authority forms as included in SABS 0142 [18].

Solution 2 – Net metering

In the net metering arrangement, the prosumer both imports and exports electricity from and to the utility grid and expects to be compensated for net export electricity sold to the grid as shown in Fig. 2.

The municipal meter is upgraded to a bi-directional meter, and the net result of the monthly or other periodic electricity import or export usage is charged or compensated to the prosumer.

As in the self-consumption mechanism above, the kW size of the SSPVEG installation can be limited to 25% of the prosumer NMD or incoming circuit breaker rating [6].

In this arrangement, the prosumer applies to its connected utility for a bi-directional meter via the necessary application forms [18].

Solution 3 – Feed-in tariffs (FITs)

The FIT mechanism attempts to promote and incentivise the deployment of RE and places an obligation on specific entities e.g. municipalities or utilities to purchase the electricity output from qualifying RE generators at pre-determined premium prices [5]. In many countries, RE energy has to be dispatched first if it is available [12].

The consumption and generation of electricity by the prosumer is recorded in full and billed and compensated. The prosumer therefore requires two meters as shown in one possible meter arrangement in Fig. 3.

As in the self-consumption and net-metering mechanisms described above, the kW size of the SSPVEG installation can be limited to 25% of the prosumer NMD or incoming circuit breaker rating [6].

Similarly to the net-metering mechanism, the prosumer applies to its connected utility for bi-directional meters via the necessary application forms [18].

Financial considerations

As mentioned in the introduction to this paper, this paper attempts to address the perceived or real risk to municipal revenues from the implementation of SSPVEG [3]. It should be noted that for the first time in 2013 annual national electricity usage dropped and several metropolitan electricity departments reported drops in their electricity sales in the last four years as a result of reduced usage of electricity due to higher electricity costs and energy efficiency (EE) measures undertaken by consumers e.g. light emitting diode (LED) and compact fluorescent light (CFL) lighting, solar water heating (SWH) and heatpumps [3].

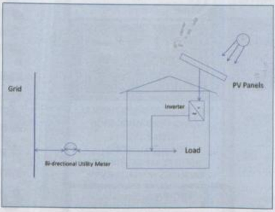

Fig. 2: Net metering with bi-directional meter.

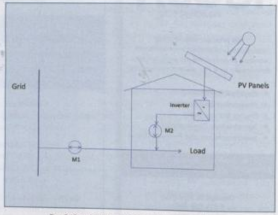

Fig. 3: Possible FIT metering with bi-directional meters.

Therefore, a reduction in municipal revenue is a reality that is occurring and needs to be accommodated and confronted with or without the introduction of SSPVEG.

In all three of the SSPVEG mechanisms described above, the question of loss of revenue exists. For every kWh not purchased from the municipality, the municipality revenue base is reduced.

Two-part tariff

One solution to this could be to introduce two-part municipal tariffs for SSPVEGs or prosumers i.e. a fixed network/service charge component and a variable kWh energy usage component. Where municipal or utility tariffs already include a service/network charge e.g. City Power's tariffs [10], this fixed service/network charge can be modified (where appropriate) when or if the prosumer:

- Notifies the utility of his intention to self-consume.
- Requests a bi-directional meter (net-metering mechanism).
- Requests two bi-directional meters (FIT mechanism).

The fixed service/network component of the two-part municipal tariff is not dependent on the level of kWh import or export and can be calculated based on a number of factors including:

- Estimated pro rata return on utility assets based on the prosumer NMD or circuit breaker size (or customer category).
- Estimated pro rata cost of utility network losses based on the prosumer NMD or circuit breaker size.
- Estimated pro rata operation and maintenance costs based on the prosumer NMD or circuit breaker size.
- Capital charge on new bi-directional meter/s.
- Connection charges.
- Sales and customer services (SACS) charges and administration charges.
- Subsidies for life-line or low income electricity consumers.

The above fixed service/network charge could also be viewed as a use of system (UoS) charge, i.e. a fixed charge to the prosumer for the privilege of being connected to the grid (as opposed to being an off-grid consumer) especially for the occasions when the sun does not shine and the prosumer requires to purchase power from the utility and for the occasions when the prosumer wants to utilise the grid to export and sell his surplus generated electricity.

The energy or kWh component of the two-part municipal tariff can be calculated as follows:

- To recover electricity energy purchases costs from Eskom (e.g. at the Megaflex tariff [21]) to supply electricity to the prosumer.
- To compensate the prosumer for energy purchases from the prosumer to sell onto or wheel [3] onto other grid connected consumers.

Therefore, even if the prosumer does not import any electricity from the municipality/utility in a month or a designated period, the municipality/utility still receives revenue to cover its fixed service/network charges as described above.

Advantages of the two-part tariff structure are as follows:

- The municipality is compensated for its fixed costs or UoS costs even if no electrical energy is imported from the municipality by the prosumer.
- The municipality is compensated for its fixed/UoS costs when the prosumer uses the municipal network to export electrical power to other users on the utility grid.
- The energy kWh usage is recovered as it is incurred. (The prosumer export kWh tariff can match the blended Megaflex tariff [21]. The prosumer import kWh tariff can possibly be reduced over time in a phased approach to match the blended Megaflex tariff).
- Non-prosumer consumers (consumers without SSPVEG) will not be affected and their billing mechanism can remain unchanged.
- The municipality is aware of the SSPVEG installation as the prosumer has to apply for a bi-directional meter system and a two part tariff or an updated two-part tariff.

Disadvantages of the two-part part tariff:

- The lower import or purchase kWh electricity charge (over time) may encourage inefficiency. However, it could be argued that LSM7 or higher level customers who have gone to the effort of being energy responsible by installing energy saving schemes are unlikely to be markedly less efficient as a result of lower kWh energy tariffs.
- Revenue shortfalls to the municipality remain in place.

Net feed in tariff (NFIT)

The "Net Feed-in Tariff" (NFIT) proposed by Dr. Tobias Bischof-Niemz [4], proposes a central power purchasing agency (CPPA) which would be the nation-wide sole off-taker for all surplus energy into the grid from EGs. The NFIT is proposed to function as follows:

- The EG or prosumer needs to install two bi-directional meters, similar to the FIT mechanism described above.
- When self-consuming electricity, the prosumer benefits by reducing his energy costs of approximately R1,2/kWh [4].
- The CPPA compensates the prosumer with a FIT on the net energy spilled into the grid (self-generation minus self-consumption) for twenty years at a predefined tariff path. A NFIT of R0,70/kWh paid to the embedded solar PV generator (calculated by Dr. Bischoff-Niemz but unverified by the author of this paper) was found to be sufficient to stimulate the embedded solar PV market. (Normal utility power purchase price is R1,2/kWh) [4].
- The CPPA compensates the municipality for lost revenues due to self-consumed solar PV energy and therefore makes the municipality profit-neutral to the embedded solar PV generator. This would also cover the municipal fixed costs. Revenue compensation from the CPPA to municipalities is calculated to be R0,6/kWh [4].
- The funding for the NFIT and revenue compensation to municipalities is proposed to come from a mark-up or premium charge of R0,002c/kWh on all nationwide energy (kWh) sales for customers larger than 200 kWh/month for the first 500 MW of PV [4]. For 6 GW of PV installation over a period of e.g. twelve years, the nationwide energy mark-up approaches R0,03c/kWh [4].
- Only registered NFIT Prosumers will be compensated for surplus energy to the utility involved [4].

The advantages from the NFIT approach could be as follows:

- Municipalities are compensated for fixed costs and their revenue surpluses due to the R0,60/kWh revenue compensation from the CPPA [4].
- SSPVEG generation close to the loads will reduce distribution and overall system losses in most cases especially with the 25% NMD SSPVEG limit as proposed in the NRS097-2-1 document [4, 6].
- SSPVEG generation close to the loads may reduce upstream transmission and distribution of non-evening congestion.
- The R1,20/kWh versus the R0,70/kWh import/export tariff differential will incentivise load-shifting and consumer efficiency behaviour [4].
- A centrally and municipally registered NFIT system will highlight distribution congestion issues in time and assist system planning and system reinforcement [4].
- Municipal and distribution grid operators will be fully aware of all embedded solar SSEGPV generators which increases maintenance safety [4].
- Certainty about market size (e.g. 500 MW/year) will give confidence to solar PV module/inverter and balance of plant market participants to set up manufacturing facilities in South Africa [4].
- The socialised "tax" on electrical energy users for solar PV generation, R0,002/kWh, is spread among the electricity users only, so the "user-pays" principle is upheld although non-prosumers or conventional consumers need to contribute [4].

- Better control over the speed and magnitude of SSPVEG development by adjusting the NFIT according to actual market development compared to government targets [4].
- Subsidies to life-line or low income electricity users are maintained.

Disadvantages of the NFIT approach could be as follows:

- An increased tariff for all customers of R0,002/kWh so non-SSPVEG prosumers or normal consumers need to contribute to the socialised "tax".
- Setting up of another government run structure or organisation i.e. the CPPA.
- Municipalities are subsidised by society for lost revenues or to maintain a revenue surplus.

Revenue shortfalls to municipalities from the two-part tariff

The NFIT [4] approach discussed above, attempts to address the threat of revenue losses to municipalities by introducing a CPPA which compensates municipalities when prosumers self-consume their own generated electricity.

This approach poses some questions as follows:

- Should municipal electricity revenue recover municipal UoS costs as well as subsidise other municipal service costs (e.g. roads and libraries)?
- How should the fixed network/service charge component of the two-part tariff be calculated to recover UoS costs and subsidies?

The AMEU embedded generation guideline report [3] shows a calculated 1,5 to 3,6% reduction in municipal revenues for customers over 600 kWh/month depending on a range of SSPVEG uptake periods and a range of assumptions e.g. assumed sales growth, no assumed sales growth, SSPVEG uptake, etc. [3].

If fixed charges are increased to the point of cancelling out the municipal revenue shortfalls, little or no incentive remains for prosumers to install SSPVEG other than for environmental or altruistic reasons?

The AMEU EG guideline [3] further mentions an estimated R5/kW/day/installed PV service charge for SSPVEG for the municipality to recover lost revenues. This equates to a SSPVEG service charge of R300/month for a 1 kW SSPVEG installation and R1500/month for a 5 kW installation.

If an example is taken of an 80 A City Power single phase "Three part flat tariff" customer who uses 1500 kWh/month, the following situation could arise:

- Service fee: R260,52/month
- Network charge: R109,43/month
- Cumulated energy charge (for the different thresholds): R1453,60/month
- Total electricity bill for the month: R1823,55

If the customer installs a 1 kW SSPVEG system, he would have to pay an additional SSPVEG service charge of R300/month, as mentioned above.

If for the particular month being analysed, the prosumer achieves 6 kWh/day (sun is not bright for eight hours), he would make a saving on his bill of R143/month. This is less than the R300/kWh service charge described above and would be even less if the municipal energy kWh energy tariff were to reduce as a result of increasing fixed network/service charges.

This simple example shows that the calculation of fixed service/network charges would need to be studied carefully in order to both protect municipal revenues and to provide incentives for SSPVEGs.

Alternatively, UoS costs only could be recovered from a reduced fixed network/service charge and other municipal services costs could be recovered via increasing the rates and taxes components of the prosumer's electricity, water and rates bill. There is a risk that low-income consumers will be negatively affected by increased rates and taxes, however this could possibly be resolved by differentiating rates and taxes tariffs based on various factors e.g. property size, NMD, geographical area, etc.

The advantages to the increased rates and taxes approach are as follows:

- Using electricity revenue to cross-subsidise other services is reduced.
- SSPVEGs financial benefits are not eroded by other-services subsidies.

The disadvantages of the increased rates and taxes approach are as follows:

- Rates and taxes tariffs for lower income citizens may increase unless differentiated rates and taxes tariffs are utilised.

Net-metering versus FIT

The net-metering mechanism may be simpler to implement as the installation of only one bi-directional meter is required, as opposed to two bi-directional meters in the FIT mechanism, however some prosumers may prefer to know in more detail exactly what magnitude of power was exported and imported and at what times. These factors will become more important as tariffs migrate to time of use (ToU) methodologies.

Due to negative experiences in countries where aggressive SSPVEG incentives or FITs are provided [12], this paper proposes that the energy kWh tariff rate compensation to prosumers when exporting power to the grid in either the net-metering or FIT mechanism is the same or similar to the blended Megaflex tariff that the municipality purchases electricity from Eskom.

Conclusions

In this paper, the observation is made that SSPVEG installations are being carried out in the absence of a finalised regulatory and legal framework, although standards are being finalised e.g. the small-scale EG NRS097-2 standards [5, 6].

It was also noted that besides the high level of existing and projected solar PV EG implementation, there is a degree of frustration in the RE industry that not enough is being done to encourage solar PV EG in South Africa and in fact that there are real obstacles to the growth of the SSPVEG industry in South Africa [3, 8]. One of the main obstacles is the revenue risk to municipalities resulting from reduced kWh sales as existing municipal tariffs are predominantly kWh based with relatively small fixed network/service charges [1, 3, 8].

The paper overviews the technical aspects of three on-grid SSPVEG interconnection mechanisms as follows:

- Self-consumption (no change in existing meter required)
- Net-metering (single bi-directional meter required)
- Feed-in tariffs (FITs) (two bi-directional meters required)

The net-metering mechanism may be simpler to implement as the installation of only one bi-directional meter is required, as opposed to two bi-directional meters in the FIT mechanism, however some prosumers may prefer to know in more detail exactly what magnitude of power is exported and imported and at what times. These factors may become more important as tariffs migrate to time of use (ToU) methodologies.

Two financial approaches to compensating both the prosumer and the municipality resulting from the installation of SSPVEG are discussed as follows:

- Two-part tariff
- Net feed-in tariff (NFIT) [4]

The two-part tariff comprises a fixed service/network (or UoS) charge component and a variable kWh energy usage component. The fixed or UoS component of the two-part municipal tariff is not dependent on the level of kWh import or export and can be calculated to cover fixed costs based on pro rata assets associated with the NMD of the particular

prosumer or prosumer category. The energy or kWh component of the two-part municipal tariff can be calculated using a blended Megaflex energy tariff for surplus electricity sold to the municipality by the prosumer and in time (e.g. a five year window) the municipality purchase tariff can be reduced to match the blended Megaflex tariff.

The net feed-in tariff (NFIT) [4], proposes a central power purchasing agency (CPPA) which would be the nation-wide sole off-taker for all surplus energy into the grid from EGs [4]. In the NFIT approach, the CPPA compensates the prosumer at a NFIT of R0,70/kWh for surplus or export net electricity and compensates the municipality for lost revenues at a tariff of R0,6/kWh [4]. The funding for the NFIT and revenue compensation to municipalities is proposed to come from a mark-up or premium charge of R0,002c/kWh on all nationwide energy (kWh) sales for customers larger than 200 kWh/month for the first 500 MW of PV [4]. The NFIT does perpetuate the concept that municipalities should be allowed to derive revenues from electricity sales in excess of their energy purchase costs and UoS costs.

The paper explores whether municipal electricity tariffs should be maintained which recover both UoS costs and energy kWh costs and cross-subsidies to other services. It also discusses how the two-part tariff can be implemented to assist municipalities to recover at least their UoS costs. However, if fixed service/network charges are increased to the point of cancelling out the municipal revenue shortfalls, little or no incentive may remain for prosumers to install SSPVEG, other than for environmental, self-sufficiency or altruistic reasons [3]. Adjustment of fixed service/network charges would need to be studied carefully in order to both cover municipal UoS costs and life-line customer subsidies and to provide financial incentives to SSPVEGs.

Foregone municipal cross-subsidy services contributions from electricity revenues could be partly or wholly recovered via increasing the "rates and taxes" components of residential and commercial bills, however there is the social risk that low-income consumers would then be penalised with higher rates and taxes tariffs as a result. This risk could possibly be mitigated by differentiating rates and taxes tariffs based on a range of criteria including size of property, customer electrical NMD, residential area, etc.

The reality is that electricity revenues are dropping for municipalities due to EE interventions, increased electricity prices and other drivers [3]. In addition, EG fundamentally changes the traditional Eskom-to-municipality-to-customer electrical supply industry (ESI) model which has been in place for decades and new ideas and new creative solutions regarding municipal revenue recovery are required.

Recommendations

The author of this paper proposes that all three SSPVEG mechanisms (self-consumption, net-metering and FIT) are adopted in South Africa and that a phased approach may be less threatening to all stakeholders involved.

Self-consumption should be allowed to proceed immediately but prosumers should be notified that existing installations should comply with NRS097 standards and that applications and approvals to generate in parallel with the grid need to be made to the municipality or the utility. Approved self-consumption prosumers will need to migrate to an upgraded two-part tariff.

Net-metering should be allowed to proceed following the promulgation of the NRS097-2 standards and other relevant standards. Prosumers applying for net-metering will transfer to a two-part tariff and will apply for the installation of a bi-directional meter at the same time.

The FIT mechanism can follow the other two mechanisms after industry experience is gained in the SSPVEG market and when metering and billing systems are sophisticated enough to take into consideration ToU and other tariff complexities.

Municipalities should possibly explore other mechanisms of funding non-electricity services rather than using electricity revenues. One suggestion is to increase residential and commercial rates and taxes. The risk to low-income consumers can be mitigated by introducing differentiated tariffs based on various factors e.g. size of property, customer electrical NMD, residential area, etc.

The NFIT approach [4] attempts to find an equitable approach to compensating SSPVREs for electricity sold and municipalities for lost revenues. If the two-part tariff approach is found to have other challenges not identified in this paper, the NFIT approach as presented, or an NFIT approach that phases out municipal cross-subsidies should possibly be investigated further.

Acknowledgements

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Distributed generation in municipal networks: the revenue impact of solar generation

by Kevin Kotzen, Bruce Raw, and Peter Atkins, GreenCape

This paper highlights the financial impact of rooftop embedded generation on the profitability of electricity sales, focusing on the effect of various billing tariff structures. The electricity buying and selling tariff structures applicable to most municipalities are explained and the discrepancy between profits earned during different usage periods is emphasised. The generation profile of a solar panel is presented and used to show that most solar power is produced in the standard time billing period. The effect of standard time solar generation on the municipal business is then evaluated showing that up to 60% of municipal electricity gross profits, from consumers who may install PV, are at risk of being lost. A mitigation strategy in the form of time of use billing is presented as a viable, effective and fair solution.

Municipalities buy electricity from Eskom on a time of use tariff and then sell that electricity onto residential consumers at a flat rate (this is the case in almost all municipalities). The time of use tariff applies different charges per kilo-Watt hour at different times of the day and year whereas a flat tariff charges the same rate per kilo-Watt hour regardless of the time of day (there is sometimes seasonal variation in flat tariffs). Profit[1] margins on electricity will thus vary throughout the day and year. When applied, most flat tariffs result in electricity being sold at a loss during certain high demand peak periods and at a profit, of varying amount, at all other times. As such, any intervention that reduces electricity sales during high profit earning times without a significant decrease in loss-causing sales results in a potentially disproportionate decrease in gross profits.

The installation of an embedded generation system (e.g. rooftop solar photovoltaic) results in the customer purchasing less electricity during sunshine hours. These lost sales occur at a time when electricity sales are most profitable (because the Eskom ToU charges are close to their lowest at this time) and can therefore have a large impact on total gross profits. This threat is well understood by most large municipalities, however discussions with a number of smaller municipalities has highlighted that the finer details of energy efficiency and embedded generation on municipal gross profits is often not understood.

In the past the threat from solar embedded generation was largely insignificant due to cheap grid electricity and the high cost of residential photovoltaic systems. The large price increases approved by NERSA and implemented by Eskom and the rapidly declining cost of solar panels means that grid price parity[2] between solar PV and the utility tariffs is soon likely to be realised. Once grid price parity has been reached, the number of solar embedded generation installations will rise rapidly. Municipalities must be able to adapt to this change and need to have adequate strategies in place to reduce the potential effect this can have on the municipal business. Eventually, the growth of embedded energy sources is likely to force a change in the business models of electricity supply utilities.

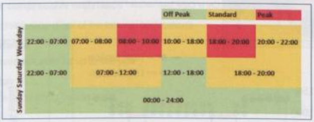

Fig. 1: Chart showing Eskom weekday time of use periods.

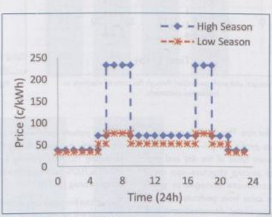

Fig. 2: Breakdown of municipal tariffs per unit of energy bought and sold.

In what follows, a detailed explanation of the current billing structure is provided. The electricity generation profile from solar panels is explored followed by an investigation into the profit lost due to solar embedded generation. The overall effect that solar embedded generation can have on the business is quantified followed by a proposal of potential mitigation strategies for municipalities.

Electricity tariffs

Municipalities typically purchase wholesale electricity on a time of use basis (ToU) and then sell that electricity to customers at a

Note 1: Throughout this paper the terms 'profit' and 'gross profit' are used to denote the selling price of electricity to the consumer minus the purchase price of electricity from Eskom. It is not intended to denote the actual profits of electricity, which would need to incorporate the true cost of supply.
Note 2: Grid price parity: the point at which the levelised cost of energy from solar PV equals the utility tariff.

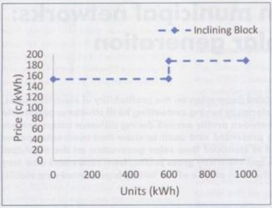

Fig. 3: City of Cape Town inclined block tariff 2014/2015. (Obtained from the City of Cape Town website.)

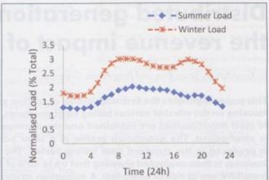

Fig. 5: Summer and winter load profiles for the City of Cape Town. Load is represented as a percentage of the total energy consumed. (Data from City of Cape Town's electrical department. Shows mixed consumption load including residential and commercial.)

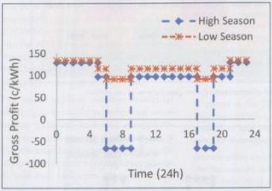

Fig. 4: Municipal unit profit generated through the sales of electricity to residential customers.

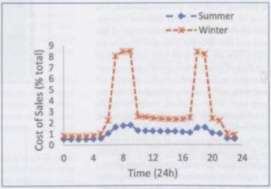

Fig. 6: Municipal cost of sales throughout the day. Cost is shown as a percentage of the total daily expenditure.

marked-up flat rate. This results in a variation in the gross profit margin on electricity sold at different times of the day and year. The current pricing structure can result in disproportionate changes in gross profits when sales from particular times of the day are increased, decreased or shifted. In order to understand this effect the tariff structures need to be fully understood.

Time of use tariff

The Eskom ToU tariff was designed to "[promote] efficient allocation", "[present a] reflective supply cost" and "incentivise desired load change" [3]. The 2014/2015 Eskom Municipal Megaflex tariff is broken down into two seasons and three tariff periods. High demand season (HD) and low demand season (LD), standard time (ST), peak time (PT) and off-peak time (OT). These periods are shown in Fig. 1.

The Eskom Megaflex pricing applied to each of these periods is shown in Fig. 2. There is a large difference in pricing between LD and HD periods and the price of electricity is significantly increased during PT, especially so during HD-PT. Electricity bought during HD-PT is 700% more expensive than electricity bought during LD-OT.

Throughout this paper only work days (Monday to Friday) will be considered. Weekends have no peak tariff periods, and as such the negative effects of flat billing are amplified over this time.

Residential flat/inclined block tariff

An inclined block tariff is designed to "make electricity more affordable to the poor" and "promote energy conservation" [4]. The City of Cape Town Domestic Tariff has two blocks as shown in Fig. 3. This tariff applies throughout the year and does not vary with season. Any electricity purchased above 600 kWh/month is charged a 20% premium.

Gross profit realised on weekday sales

Profits are generated from electricity sales by selling electricity for more than the overall cost. Fig. 3 presents an example of municipal gross profits for electricity sold at varying times of the day using a flat tariff. It can be seen that electricity is sold at a profit of varying levels throughout the day and that sales made during HD-PT incur a loss.

Customer load profile

An average load profile for the City of Cape Town is presented in Fig. 5. There are two clear daily demand peaks that occur at around 08h00 and 20h00 corresponding to the pre- and post-work peak periods.

Electricity revenue structure

Applying the relevant municipal purchase price tariffs to the load profile reveals an electricity cost of sales profile. This shows the municipal expenditure on electricity at each point in the day as presented in Fig. 6. In this figure the load is represented as the percentage of total energy cost to the municipality for that day. Analysis of this data reveals that for this example load profile approximately 40% of the total cost of sales

Kabelflex

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Kabelflex is a revolutionary, purpose designed flexible cable conduit system developed in Germany and manufactured in South Africa. **Kabelflex** has a unique double walled corrugated construction and is manufactured from high density polyethylene (HDPE).

- **Jointing**
  Joined with push fit couplings providing IP30 index protection
- **Impact resistance**
  Far superior to uPVC sewer pipes
- **Excellent compressive resistance**
  Due to the reinforcing effect of the external corrugations
- **UV Resistance**
  Can be stored outdoors for up to one year
- **Installation**
  Light, clean and easy to handle

Technical data:

Standard conduit colour is black, other colours available on request. **All specifications are subject to manufacturing tolerances.**

Kabelflex conduit size	DN50	DN75	DN110	DN160
Outside diameter (mm)	50	75	110	160
Inside diameter (mm)	40	63	95	137
Standard straight length (m)	n/a	6	6	6
Standard length coils (m)	50	50	50	25
Min. bending radius (mm) 6m length	n/a	1 400	2 500	4 000
Min. bending radius (mm) coils	150	250	350	450

Technical Properties HDPE

Property	HDPE	Unit	Test method
Density	appr. 0.95	g/cm^3	DIN 53 479
Tensile strength at break	23 – 30	N/mm^2	DIN 53 455
Ball indentation hardness	30 – 65	N/mm^2	DIN 53 456
Notched bar impact strength	> 5	mJ/mm^2	DIN 53 453
Thermal conductivity	0.40 – 0.46	W/m K	DIN 52 612
Coefficient of elongation	$1.5 - 2.0 \times 10^{-4}$	K^{-1}	DIN 52 328
Dielectric strength	800 – 900	kV/cm	DIN 53 481
Specific insulation resistance	appr. 10^{16}	Ohm . cm	DIN 53 482

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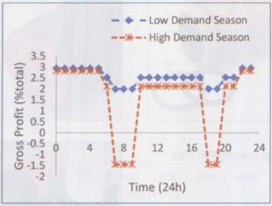

Fig. 7: Municipal gross profits earned throughout the day.

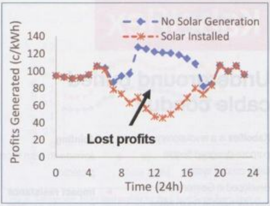

Fig. 9: Low demand (summer) unit profits generated with and without solar embedded generation.

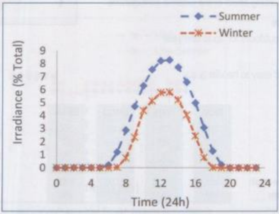

Fig. 8: Graph showing irradiance/generation profile of a solar panel in Cape Town during summer and winter.

is incurred during HD-PT which only makes up 14% of the total energy purchase.

Similarly when gross profit margins are applied to the load profile a gross profit profile is developed. The gross profit profile for this example shown in Fig. 7 confirms that profits are made outside of PT, with 50% of total gross profit coming from ST sales.

PV generation

In order to determine the impact that solar embedded generation will have on the gross profits from electricity sales, the generation profile of the solar panels needs to be known. Photovoltaic (PV) electricity production is directly related to the irradiance level of sunshine. The study below focuses on the effect of PV generation, but similar results will be found from any distributed energy source (e.g. solar hot water) that has its primary effect during sunshine hours.

PV irradiation/generation profile

A normalised irradiation profile for Cape Town is shown in Fig. 8. Up to 87% of total energy is generated during ST (between 09h00 and 18h00). A small amount of electricity is generated during PT and no electricity is produced during OT. Significantly more electricity is produced during LD than during HD.

Embedded generation impact

Given the electricity gross profit profile (Fig. 6) and photovoltaic generation curve (Fig. 7), the effect that solar embedded generation has on municipal gross profits can be calculated. Solar embedded generation only affects profits which were earned during sunshine hours. As such only OT gross profits are unaffected by solar embedded generation. OT gross profits account for 40% of the total gross profit earned, leaving 60% of electricity gross profit at risk of being impacted by solar embedded generation.

PV panels have low output during HD-PT and thus offer little direct benefit in reducing municipal load during this time. While it is possible to optimise PVs for HD-PT production to some extent, it is unlikely that this will have a significant effect. Solar embedded generation should therefore not be considered as a peak load reduction method, unless other actions such as customer load shifting or energy storage are undertaken.

Overall effect on gross profits generated

Embedded generation systems are expensive at present and would typically only be installed by high-end customers. These customers consume electricity from the most expensive residential inclined block tariff and thus even a small reduction in sales from these customers can result in a big loss of highly profitable sales. Figs. 9 and 10 show the change in gross profits when a solar embedded generation system is installed in an average large consumer household.

The effect of solar embedded generation on municipal profits is best demonstrated with an example. Example 1 presents a quantitative illustration of how this would affect a typical large household in terms of lost gross profits to the municipality.

Example 1: Given the installation of which 1,5 kW peak PV system on a household uses an average of around 1000 kWh of electricity a month. The municipality stands to lose an average of 270 kWh per month of sales from the Block 2 electricity tariff[3]. The lost sales occur predominantly during standard time

Note 3: Block 2 is the higher tariff in the inclined block tariff used in this example.

and are equivalent to about R330 per month of lost gross profits. This represents a 25% decrease in total gross profits earned from this household.

What can be done

Municipalities can take a number of steps to mitigate the impact of solar embedded generation on electricity gross profits. Legislation can be used to prevent customers from installing solar embedded generation, or a monthly solar embedded generation tariff can be charged. These actions may however be considered punitive and may result in an increase in illegal solar embedded generation connections. A solution which modifies consumer electricity pricing to reflect the cost price (e.g. from Eskom) could be considered the most fair. Residential ToU billing with a fixed service and connection charge is the implementation of this tariff structure.

Effect of residential ToU tariff

A basic analysis of the effect of a residential ToU tariff on the impact of solar embedded generation was carried out. This analysis compares the revenue lost based on a flat tariff, compared to that with a revenue neutral ToU tariff (total revenue on ToU tariff does not differ from that of flat tariff for the same consumption). This analysis does not include any load shifting from the user, which would add additional complexities, but is generally seen as beneficial to the municipality. The reduction in unit gross profits in HD season due to solar embedded generation for a flat tariff and a ToU tariff are compared in Fig. 11.

While the ToU tariff results in a small loss for the duration that PV produces during PT, for the major portion of the day the loss is significantly decreased. On weekends there is no peak, and thus an even greater loss reduction is realised. Again using the scenario presented in Example 1 the overall gross profit losses are now reduced by approximately 40%, bringing the total loss down to around 10%.

Note: A change in tariff structure will affect the financial model of solar embedded generation for a customer. This may result in fewer customers installing PV which may have an impact on the local economy.

Conclusion

The asymmetrical buying and selling prices of electricity results in different levels of gross profit being generated from the sales of electricity on an hourly and seasonal basis. Electricity is sold at a loss during high demand peak time and for a large gross profit during low demand standard and peak time.

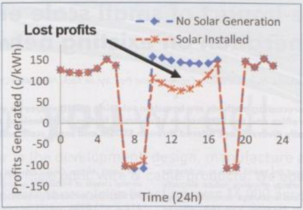

Fig. 10: High demand (winter) unit profits generated with and without solar embedded generation.

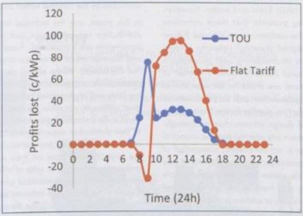

Fig. 11: Comparison between unit profits lost due to PV for a flat and residential time of use tariff.

Solar embedded generation produces most of its energy when gross profit margins are greatest and hence can have a potentially disproportionate effect on kilo-Watt hour sales lost vs gross profits lost. Time of use billing is explored as a mitigation strategy and is shown to have a positive impact in protecting municipal revenue.

Acknowledgements

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The impact of small scale embedded generation on existing networks

by Jaco Alberts, Motla Consulting Engineers, and Prof. Jan de Kock, North West University

Load forecasting methods are based on selecting ADMD values for various load classes, summating the load class load profiles and the application of diversity factors while looking ten to 20 years into the future. These factors, especially diversity, are altered through EEDSM and small scale embedded generation initiatives.

Throughout the world there is a drive to improve energy efficiency, reduce electricity demand and encourage renewable energy generation. The public is generally informed through media that this is good for the environment, will prolong generation and grid assets as well as natural resources such as fossil fuels and water. However, it may be possible that these initiatives change the performance of planned (future) and designed (existing) networks without engineers reconsidering past assumptions or traditional methods. Quite a number of assumptions are made in the selection of suitable parameters and combinations of parameters to predict future load and to plan and design infrastructure accordingly. If parameters are affected and the impact of a change is not considered, unexpected or even degraded performance of networks may result while utilities and municipal electricity re-sellers may have to lay out unplanned capital to rectify or address problems caused.

Distribution networks are not designed to cater for reverse power flow or a diversity-less scenario (e.g. solar PV power injection at rooftop level into the grid). The paper will investigate the impact EEDSM and small scale embedded generation may have on these parameters used for master planning and designs, how it will affect existing networks and which concerns we should address for our future cities in this regard.

The South African Grid Code has defined several classes of embedded generation [1]. For this paper, embedded generation of Class A1 (i.e. <13,8 kVA) and EEDSM initiatives for the low voltage domestic load class will be considered. This form of generation is called embedded generation, because it cannot be controlled by the national system operator.

In this paper, only the technical impact on distribution network design and planning parameters are considered. Power quality and financial impact to revenue streams are not considered. While energy saving and demand side management (EEDSM) initiatives are fairly well implemented by many utilities, most utilities do not allow the connection of small scale embedded generators at present to their distribution networks pending further regulations, by-laws and certainty about the impact it will have on their networks and revenue streams. In spite of utilities not allowing small scale embedded generation, it exists in the distribution networks already in South Africa, and the location thereof in the networks are not only unknown to utilities, but can also not be controlled by utilities.

NRS 097-2-1:2010 Grid Interconnection of Embedded Generation [2] attempts to provide some guidance to the implementation and compliance of embedded generation.

Load forecasting, related planning and design parameters

In electricity distribution network designs and master planning, various assumptions have to be made while the designer or planner considers future loading and scenarios. Load forecasting is an integral part of any network design and considers a saturated maximum demand state 15 to 20 years into the future. The load forecast is determined by considering a combination of diversity factors, load factors, load profiles, loss factors, growth rate and after diversity maximum demand (ADMD). Once the end state load is known, network elements can be sized based on voltage drop, current carrying capability and fault level considerations.

Much work has been done internationally over the years to develop tools and formulae to predict and calculate diversity from as early as the late 1930s [3] on domestic loads for LV network design and to calculate maximum demand from ADMD during the early 1950s [4] (deterministic methods).

Coincidence and diversity by definition are:

$$Coincidence = \frac{total\ MD}{\sum Indiv\ MDs} \quad (1)$$

where

MD = Maximum demand,

$$Diversity = \frac{1}{Coincidence} \quad (2)$$

Boggis [4] and Mcqueen [5] related maximum demand, ADMD and diversity factor (DF) as:

$$MD = N \times DF \times ADMD \quad (3)$$

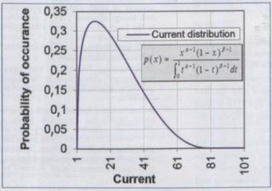

Fig. 1: Beta distribution curve with parameters α=1,37, β=3,39, c=80, ADMD=5,3 kVA (NRS034 Table 2, LSM 8 high end).

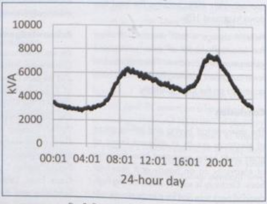

Fig. 2: Domestic 24-hour load profile.

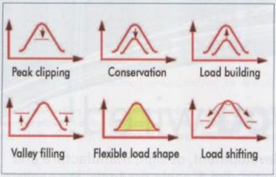

Fig. 3: Impact of EEDSM initiatives on load profiles.

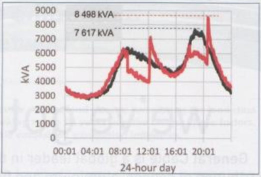

Fig. 4: Effect of cold-pickup load on a ripple control system, indicating an ADMD increase.

ADMD change	Revised ADMD kVA	α	β	C
5,3 kVA Designed	5,3	1,37	3,39	80
5,0 kVA + 11,6%	5,8	1,29	2,83	80
5,0 kVA + 25%	6,25	1,21	2,37	80

Table 1: Ripple control impact to Beta distribution curve modelling parameters.

$$ADMD = \lim_{N\to\infty} \frac{1}{N}\sum_{i=0}^{N} MD_i \quad (4)$$

$$DF = 1 + \frac{k}{N} \quad (5)$$

where

k = Coincidence

N = Number of consumers

Later theory suggested that a homogenous group as small as 100 consumers were sufficient to produce an accurate ADMD value. However, the CSIR [6] suggests that a 1000 consumers form a representative sample size to determine an accurate ADMD.

In some cases, as described in [4], Eqn. 5 also existed in the form

$$DF = 1 + \frac{k}{\sqrt{N}} \quad (6)$$

Voltage drop calculations were initially based on empirical formulae (deterministic methods) such as British and AMEU diversity correction curves with neutral unbalance compensation), followed by statistical distribution curves (probabilistic methods) such as the Herman-Beta method [7, 8]. Lately, the USA and Australia are considering stochastic methods as opposed to the probabilistic methods, considering a larger dependency on other factors such as time, temperature, humidity, cloud cover, etc. [9].

The Herma-Beta distribution curve [7] still relies on an ADMD parameter to be selected, while diversity correction is applied through the selection of α and β parameters to model the probability of a consumer drawing a specific current at peak time.

Present ADMD is still the best determined by measurement, while future ADMD draws on the experience of the planner to combine load growth, income level and other factors to produce a suitable figure. Consider the following 1-minute domestic load profile:

For this load profile, the maximum demand of 7617 kVA was recorded at 18h47 on a given day. For 1511 domestic consumers and streetlight load of 62 kVA, the present ADMD is:

(7617 – 62) / 1511 = 5,0 kVA / household.

It is to be noted that the measurement interval plays a significant role in the ADMD measurement. The longer the measurement interval, the larger the error between the integrated peak and the instantaneous peak.

The projection of this ADMD into the future requires the application of S-curve load growth theory, as well as knowledge of network load maturity. If this network was designed at a 5,3 kVA ADMD, it is 94% mature at present.

Following determination of a final load, the network can be designed. What happens when design parameters change? The following two sections of this paper examine simple changes to e.g. ADMD through residential load control, such as ripple controlled geyser switching, as well as small scale embedded generation such as solar PV.

EEDSM

EEDSM generally refers to energy efficiency and demand side management. Generally, the following figure is used to explain the various techniques:

Energy efficiency, or conservation, generally reduces the demand and energy, which does not have a negative effect on the distribution network. This is already deployed by many utilities and customers, such as more energy efficient streetlights, domestic CFL roll-out, replacement of fluorescent lamps in offices with more efficient lamps, replacement of conventional geysers with heat pumps and solar geysers etc.

Demand side management usually involves load shifting, which is in effect a combination of peak clipping and valley filling. Domestic ripple control is one such an example rolled out to domestic users to reduce the maximum demand during the morning and evening peak. In this case, no energy is conserved, just moved. When load profiles containing ripple controlled geysers are investigated, it has been observed that the cold load pick-up resulting from the load shift sometimes exceeds what would have been the original peak. By definition, the ADMD has increased and the load factor decreased due to a lack of diversity on a certain load portion of the network, in this case the geyser load. In many cases, the utilities save on their revenue bills purely by consuming the energy at a more cost effective time. Consider a typical recent example, Fig. 4, where the load profile a controlled day is superimposed on the profile of an uncontrolled day.

From this observation, the ADMD has increased by 11,6% while studies by an Italian distributor have indicated as much as a 25% increase [8]. Very often, control does not take place at the 11 kV level, but at the billing level, e.g. 132 kV, in which case occurrences such as these can be expected. The discussion of improved control algorithms at multiple network levels are excluded from this study.

It must be noted that measurement error, when considering for instance 30-minute integrated data vs. 1-minute integrated data, can be as high as 15% (specifically observed for the load-controlled profile in Fig. 4).

By considering an example low voltage feeder, designed at 5,3 kVA ADMD, the impact of an ADMD increase can easily be observed through load flow analysis.

The Beta distribution curve parameters based on the design ADMD as well as the revised

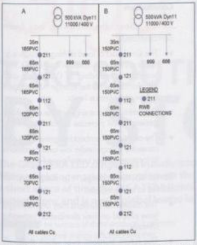

Fig. 5: Sample LV feeder for two scenarios: Tapered LV feeder (A) and the same cable size used right through (B).

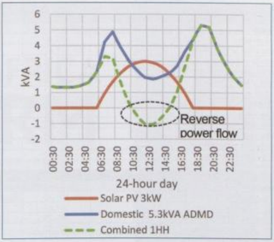

Fig. 6: Impact of solar PV to an averaged domestic load profile.

ADMD for two scenarios, should an increase of 11,6% and 25% respectively occur to present day ADMD of 5 kVA, are as follows:

For an example low voltage (LV) feeder system, two scenarios are considered:

A: A tapered LV feeder with only certain cable sizes used. Here, a circuit breaker is required at each change in cable size.

B: An LV feeder with the same size right through. Here, a circuit breaker is only required at the transformer to protect the cable.

All LV cables in these two scenarios are copper cables. Service connections are 16 mm² two-core, 30 m when on the same side of the road as the LV distribution or metering kiosk, and 43 m when on the opposite side of the road.

Two additional feeders are shown connected to the transformer secondary wind in order to correctly simulate voltage drop across the transformer.

The phase allocation is such that each feeder contains an equal number of consumers per phase, although the three feeders are of different length. For Scenario B, the feeder is designed to include as many domestic customers as possible to be just within the maximum allowed voltage drop, considering nominal tap transformer settings and assuming a 1 p.u. MV voltage. The cables were then changed for Scenario A, and covered only four types of cables, as many utilities only stock a certain number of cable sizes in their stores.

The results of a load flow analysis are as follows:

These results demonstrate that:

- The lowest voltage at a customer distribution board drops below the minimum allowed voltage of 0,9 p.u.
- Transformer loading increased by 17%, although in this example the loading is still within the overload conditions allowed by the transformer manufacturer, provided that the overload duration remains below four hours in a 24-hour cycle.
- For scenario B, the conductor section closest to the transformer has exceeded rated capacity.
- For both scenarios, at significant ADMD increase, the allowed maximum voltage drop is reached before the end of the feeder.

Embedded generation

Embedded generation in the LV network regions of distribution networks are difficult to control by utilities. With rising electricity prices, it is possible that the levelised cost to install e.g. solar PV may soon outweigh the cost when purchasing from the utility. There are already solar PV panels installed on distribution networks with the possibility of reverse power flow in the case of excess power. Distribution networks were traditionally not designed for reverse power flow since almost all LV feeders in South Africa are radial feeders.

During low load, conditions are such that any excess energy not consumed by the premises itself could flow into the network. According to impedance paths and phase injected on, the energy will flow to the nearest load on that phase. This in itself creates unbalance elsewhere in the network, which increases voltage drop. Generally, the voltage rises where a generator is connected while the distribution network is traditionally designed to mitigate voltage drop. Distribution transformers are on fixed taps, and cannot adjust itself to compensate for increased voltages on the LV network. The networks are further designed with diversity between loads in mind. If the amount of energy injected into the network during low load conditions is not controlled, there exists the possibility of overloading sections of the LV cable network due to a lack of diversity between multiple solar PV embedded generators.

ADMD (kVA)	Trans-former load (kVA)	Min V (% of nominal)	Highest loaded cable (% of rated current)	% distance reach of LV feeder @ 90% V
Tapered LV cable feeder (A)				
5,3	478	90,14	77	100
5,8	519	89,28	84	73
6,25	560	88,44	90,9	60
One size LV cable feeder (B)				
5,3	478	91,34	88	100
5,8	519	90,59	96	100
6,25	560	89,85	103,5	85

Table 2: Results of load flow for two sample feeder designs at 11,6% and 25% ADMD increase.

Scenario	Transformer load (kVA)	Min V %	Max V %
3 kW solar PV embedded generator systems			
Tapered LV feeder			
No generator connected	150	101,40	103,42
Single generator close to transformer	147	101,47	103,44
Single generator at end of feeder	147	101,32	103,44
25% penetration close to transformer	90	101,60	103,56
25% penetration at end of feeder	90	102,02	103,76
100% penetration	-68	103,67	105,33
One size LV feeder			
No generator connected	150	101,64	103,42
Single generator close to transformer	147	101,72	103,29
Single generator at end of feeder	147	101,58	103,44
25% penetration close to transformer	90	101,85	103,56
25% penetration at end of feeder	90	102,12	103,58
100% penetration	-77	103,68	105,23
9 kW solar PV embedded generator systems			
Tapered LV feeder			
No generator connected	150	101,40	103,42
Single generator close to transformer	141	101,61	103,48
Single generator at end of feeder	141	100,39	104,39
25% penetration close to transformer	42	101,82	103,90
25% penetration at end of feeder	42	102,95	107,34
100% penetration	-247	104,15	111,96
One size LV feeder			
No generator connected	150	101,64	103,42
Single generator close to transformer	141	101,88	103,48
Single generator at end of feeder	141	100,77	104,09
25% penetration close to transformer	42	102,09	103,95
25% penetration at end of feeder	42	102,93	106,48
100% penetration	-255	104,17	111,26

Table 3: Solar PV embedded generation load flow results.
(Negative transformer load indicates reverse flow).

The effect of solar PV power injected into the network from house-hold level on voltage rise will be demonstrated through load flow analysis. Although fault level generally should increase when generators are connected to the network, the effect on fault level will not be illustrated or discussed further in this paper.

Consider a 5,3 kVA load profile, averaged for a single consumer, with a 3 kW solar PV plant (at unity power factor):

From this graph, it is evident that a surplus energy could exist during low load conditions when the energy produced by the solar PV cell cannot be utilised by the household. In reality, the load profile of a single consumer is not as smooth, and the solar output can be affected by ambient temperature or cloud cover. During reverse energy flow conditions, voltage rise can take place. This is especially a concern where solar PV embedded generation takes place close to transformers with internal boost (3,75% for 415 V secondary or 5% for 420 V secondary side transformers), or raised taps.

It is also clear from the vertical scale in this graph that any larger embedded PV system will send larger amounts of energy back into the network.

It is further clear that the impact during the evening peak will be virtually zero (the solar curve has been drawn for a 06h00 to 18h00 solar day), while the morning peak can be considerably reduced.

It must be noted that if another form of generation, e.g. micro wind turbines or systems with excess storage would inject single phase power during the peak period resulting in unbalanced conditions occurring on a previously balanced feeder designed to its limits, voltage regulation violations could occur.

The effects of voltage rise and the impact to feeder ampacity are illustrated considering the two feeder systems in a load flow analysis.

For scenarios A and B, the following solar PV scenarios are considered at maximum reverse power flow conditions:

- 3 kW solar PV embedded generators for a transformer with 3,75% internal boost (i.e. a 415 V system)
- 9 kW solar PV embedded generators (415 V system)

For the 415 V system, voltage drop per phase is still measured relative to the declared nominal voltage of 230 V in South Africa.

The results are shown in Table 3.

From these results, it is noted that:

- Voltage rises as generators are added.
- Under higher embedded generation load, and high penetration, the maximum voltage limits can be exceeded and excess power flows across the transformer into the MV network.
- Although no cables were overloaded under any reverse power flow conditions in these examples, under very high embedded generation load (e.g. each house inject 60 A after own utilisation) LV feeder sections will become overloaded due to a lack of diversity between generators.

Conclusion

In this paper, the following has been demonstrated:

- The simple act of load shifting through e.g. ripple control can increase the ADMD, with possible overloading of LV feeders and transformers while the voltage has dropped below compliance limits.
- The addition of one single phase embedded generator will increase unbalance.
- The addition of embedded generators can cause the voltage under low load conditions to increase above compliance limits.

Based on the findings, it is necessary for utilities to contemplate:

- The additional burdens they unknowingly have placed on their distribution networks already.
- The future burdens over which they will not easily have control.
- How they will deal with the technical implications of future EEDSM and embedded generation aspects.

Much work must still be done to increase our understanding of the impact of new technology and to develop new design methods in order to ensure continuous robust, compliant and safe networks.

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GigaTera® TAKE SOUTH AFRICA BY STORM

The GIGA TERA LED range was initially introduced into the South African lighting market to supplement the successful ES Streetlight. In a short space of time the GIGA TERA lighting range has surpassed all expectations and is now a global leader in LED products.

The success of these products is reflected in their energy efficiency and their ability to improve existing lighting levels. The superiority of these world-class products is evident in the fact that they have already been awarded the Energie de France global energy efficient award for High Mast Lighting. The energy efficient project in the Nelson Mandela Bay Municipality (NMBM) showcased the GIGA TERA High Mast Lights, not only did it win this prestigious award but it caught the attention of the President and Minister of Energy. So much so that it has been endorsed by the Minister of Energy as "One of the best service delivery programmes ever undertaken by a municipality."

The success of this project has resulted in GIGA TERA replacing all the major road streetlights on NMBM's highways. These LED products have resulted in over 100% improvement with regards to lighting levels, whilst reducing energy consumption by 56% (The inset table reveals these impressive readings – these were captured by an independent engineer on behalf of NMBM).

LIGHT READINGS – NMBM M4 SETTLERS HIGHWAY – 06 OCTOBER 2014

	4 x 400w HPS	4 x MAHA 200w LED
EAVE	10.9	22.6
Uo	0.69	0.86
Ul 1	0.59	0.94
Ul 2	0.59	0.91
Ul 3	0.61	0.86

TSHWANE BUS RAPID TRANSPORT SYSTEM (BRT)

Tshwane Bus Rapid Transport System (BRT) has identified GIGA TERA products as their preferred lighting solution. GIGA TERA has been awarded this contract and there is no doubt that it will be as successful as the NMBM project. The BRT is a high-status project; it involves the supply of luminaries together with an integrated management and monitoring system. GIGA TERA together with the Tshwane Municipality aim to produce an energy efficient and effective solution for the BRT System.

THE SECOND-GENERATION HAS ARRIVED

GIGA TERA have introduced the second-generation LED products into the South African commercial and industrial lighting industry. The range includes High Bays, Floods, Wallpacks, Troffers, Security, Sports and Car Park lighting. This range covers a spectrum of wattage and applications.

The Products manufactured by KMW are second-generation LED products that utilise highly sophisticated reflector technology, this reduces glare as well as creates excellent uniformity. The luminaire is designed in such a manner that it maximizes heat dissipation and performance. The second-generation luminaires generate quick paybacks as the lights out out over 120lm/w on the fixtures. Thus resulting in the creation of more light with less wattage.

Another attractive feature of GIGA TERA products is that (before being launched into the market) the entire product undergoes an accelerated heat test (± 80°C) for a period of two months. This ensures sustained functionality over the products extended life. Majority of competitors' products use systems known as "Thermal Controllers". These "Thermal Controllers" reduce light in order to manage the build-up of heat. GIGATERA considers this inappropriate as these systems not only create dangerous situations but cannot guarantee operations at the designed lux levels at all times.

GIGA TERA's dedication and determination in providing an energy efficient and effective luminaire is evidence that they are the ultimate lighting solution.

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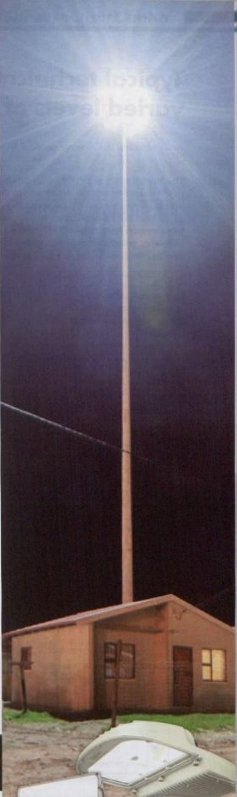

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switch on savings

Typical technical behaviour of LV networks with varied levels of renewable penetration

by GV Moodley, Dr. GD Jennings and V Pillay, DigSilent Buyisa

The installation of LV, PV embedded generation is steadily growing worldwide, largely driven by the reduction in PV module costs. In South Africa there are several technical concerns about the impact high penetration levels of embedded PV generation will have on LV networks. A typical 400 V network was taken and the impact of 23 and 54% penetration of embedded PV generation was analysed. The results show that for moderate penetration levels the effect on the feeder voltage profile can be positive. Reduction in losses and the reduction in feeder peak demand are also noted. Where there is little correlation between generation pattern and load profile, the shifting of the feeder peak and voltage "swings" are noted.

South Africa is still in its infancy with regard to renewable energy installations and all of this is at transmission and sub-transmission level. However in countries with high penetration of embedded renewable generation, the bulk of this is at LV level, e.g. Germany has approximately 90% [1] of its total PV installation of 35,67 GW [2] installed on rooftops. Current trends indicate that for the renewable market to really take off in South Africa, embedded generation needs to take place at LV level. The question then raised is what technical impacts is this going to have on networks which were designed to transfer power from the "top down". This paper presents results of studies that show the typical technical behaviour of LV networks, with varied penetration levels of renewable generation, and gives some indication as to how to manage these developments.

Global trends

While South Africa still finalises the policies and regulations surrounding the installation of renewable generation sources at LV level, the world continues its development of renewable generation sources with 22,1% of global electricity being produced from renewable energy by the end of 2013 [3]. China and the US continue to lead in the investment into renewable generation. Most significant in 2013 was that there was more PV installed (39 GW) than wind generation (35 GW) [3]. This is a significant trend for South Africa because while solar geysers and heat exchangers remain a primary source of LV load reduction, PV panels are the most viable source of electricity generation. To further strengthen PV installation growth worldwide, the installed capacity of PV increased while the investment into PV decreased, as shown in Fig. 1. This is primarily due to the reduction in module prices. Such a trend is significant for developing nations as the cost of renewable energy still remains a major factor.

Concerns of effects of embedded generation on LV Networks

LV networks are traditionally designed to transfer power from the "top-down". With global trends indicating the steady increase in installations of PV at LV level, the concerns on the adverse effects of LV embedded generation needs to be carefully studied and managed, especially as South African networks are different in their design from European networks.

Some of the technical concerns currently being discussed are:

- Effects on voltage
- Effects on thermal loading and peak demands
- Effects on the network losses
- Effects on feeder protection
- Safety

These concerns are certainly relevant, and analysis of the impacts of varied levels of embedded generation at LV level is therefore vitally important to quantifying these effects.

Case study results

LV feeder studied

In order to perform studies, a typical LV feeder was chosen. The feeder has the following properties:

- 400 V
- 470 m long cable network
- Peak demand = 198 kW (no embedded generation)

The embedded generation considered on the feeder was PV at randomly chosen injection points. The penetration levels studied were 0%, 23% and 54% of peak feeder demand (0 kW, 45,9 kW, and 107 kW).

Fig. 2 is a schematic representation of the feeder. All studies were done using Digsilent's Powerfactory software, V15,1 [4].

Generation and load profiles

Traditional network planning studies consider mainly the feeder peak demand. With embedded generation, the nature of the generation and the time dependent generating pattern must be taken into account. As such, using only the peak load demand is no longer adequate to fully analyse the feeder and a full load profile over the same time period as the generating pattern is required.

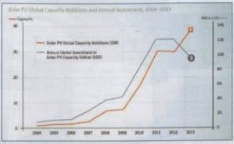

Fig. 1: PV growth despite reduced investment for 2013 [3].

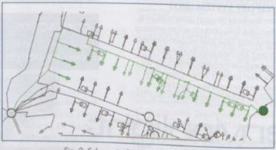

Fig. 2: Schematic diagram of feeder studied.

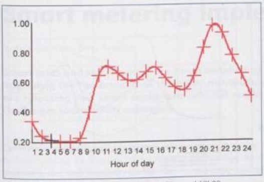

Fig. 3: Domestic load profile with peak around 19h00.

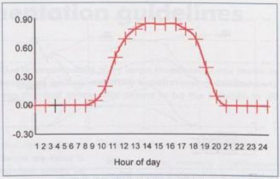

Fig. 5: Rooftop PV generation pattern.

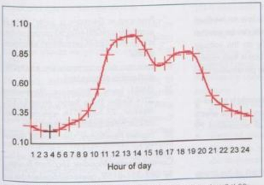

Fig. 4: Light commercial/professional load profile with peak at 24h00.

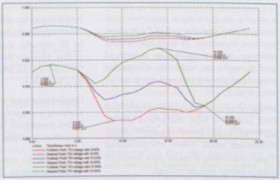

Fig. 6: Effect on feeder voltage profile.

Generation	Feeder peak	Time
0%	198 kW	10h00
23%	167 kW	18h00
54%	161 kW	19h00

Table 1: Reduction in feeder peak demand.

For the feeder considered, two load profiles were used, namely a domestic load and a light commercial/professional load. The mix of the load types in the feeder was 33% domestic to 67% light commercial/professional. Figs. 3 and 4 show the profiles of the load types.

The generation profile of a typical PV plant must also be considered. Fig. 5 shows the generation profile of the rooftop PV with typical operating hours between 06h00 and 18h00.

Effect on voltage profile

The feeder profile voltage was monitored at the infeed point (first load connection point) and at the last connection point along the feeder. No voltage changes at the MV/LV transformer was considered. The results indicate that the impact of the embedded PV generation on the feeder voltage profile is most significant at the end of the feeder. Fig. 6 shows the feeder voltage over a day.

While the effect on the voltage profile is most pronounced at the end point, the improvement in voltage profile is noted where the generation matches the load demand and there is a moderate penetration level.

In the case of no generation, the maximum voltage swing is 5% occurring between 02h00 and 09h00. With high generation penetration, a 5% voltage swing is still noted but it occurs between 14h00 and 19h00. The results in this study show that the high penetration level shifts the maximum voltage swing, but does not alleviate it.

Effect on feeder peak demand

The effect on the feeder peak demand is shown in Fig. 7. The results indicate a reduction in the feeder peak demand and a shifting in the time of the feeder peak.

Most noticeable is that if the generation profile does not match the load profile there is no significant reduction in the reduced peak demand. Table 1 shows that the PV generation has managed to reduce the peak feeder demand that was predominantly caused by the light commercial loads. However, an increase from 23 to 54% generation penetration has little effect on feeder peak, which is caused by the domestic load peak at 19h00 (after the PV plants have stopped producing power).

Losses

The most significant reduction noted is with the feeder losses. LV networks are predominantly resistive and the impact on losses will therefore be significant. Fig. 8 shows the reduction in the feeder losses.

Challenges for Southern African LV Networks

Unlike European LV networks that are balanced, South African LV networks are predominantly single phase. Load balancing between the phases is a problem that has long faced network operators. With single phase PV becoming more affordable, the concept of single phase "generation balancing" is also likely to become a factor that has to be carefully assessed on a feeder by feeder basis.

In order to perform this feeder level analysis, knowledge of the feeder is required. An advanced database and GIS systems will be required in order to hold information such as:

- Feeder cable types and lengths.
- Feeder peak demands.
- Feeder load profiles.
- Customer connection types.

Further to this, this information will need to be processed and seamlessly passed to the simulation and analysis tools. Bulk analysis of multiple feeders will be required.

Conclusion

Embedded PV generation is going to become

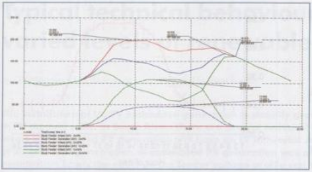

Fig. 7: Effect on feeder peak demand.

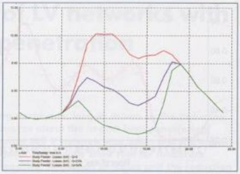

Fig. 8: Reduction in feeder loses.

a reality as customers become more "energy savvy" and the cost of PV modules continue to reduce. As such the network operators need to be able to understand and quantify the technical effects the embedded generation will have on LV networks.

Where correlation between generation and load profiles is high, the effects can be significant, especially with respect to voltage profiles and losses. Where little correlation is seen, the shifting of feeder peak times and voltage swings may be noticed.

Furthermore, for relatively low to medium penetration levels, the effects can be positive for LV networks, especially on the voltage profiles. However, the question is then raised: "What is a suitable allowable penetration level for a feeder?"

Detailed knowledge of LV networks is crucial to analysing and managing any adverse effects varied penetration levels of embedded PV generation may have.

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Smart metering implementation guidelines

by Kobus van den Berg, Aurecon

Smart grids and smart meters are being installed by utilities internationally. Very large investments are made in upgrading the "smartness" of the utility distribution networks as well as metering installations. Manufacturers are releasing new smart equipment onto the market every day and every offer seems to be the solution to all challenges facing utility managers.

Financial managers may perceive these technologies to be a quick fix for their revenue losses and financial viability. The big challenge however is the substantial investment (financially and skills) required to install and operate the new devices.

The obvious question arises: "What should my utility do to ride this new wave of technology and how should we go about doing it, if at all?"

The basic definitions and functionality of smart metering systems and the approach to ensure effective rollout and operation of these systems are discussed. The implementation of smart metering in the South African context concentrating on the objectives and strategies will be discussed without digging into complex technical detail too much

Smart grids and smart metering

Smart grids (SG) include smart metering (SM) and is essentially a process of installing intelligent devices in distribution networks to monitor and control the system by using computer and data communication technology. All these devices are linked to the utility back office computer systems via communication channels to transfer data from and to field installed devices. The power of the SG is embedded in the use of this information to control and manage the distribution system to improve reliability and efficiency.

According to SANEDI's (South African National Energy Development Institute) vision document a smart grid includes the following functions:

- Advanced metering infrastructure (AMI)
- Customer side systems (CS)
- Demand response (DR)
- Distribution management system/ distribution automation (DMS)
- Transmission enhancement applications (TA)
- Asset/system optimisation (AO)
- Distributed energy resources (DER)
- Information and communications integration (ICT)

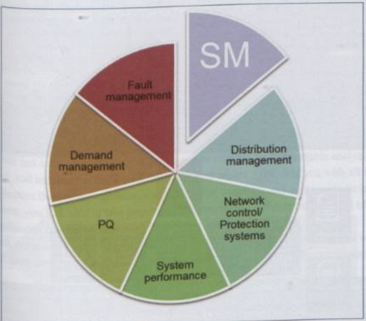


Fig. 1: SG functional components.

What is SM?

AMI (advanced metering infrastructure) or SM (smart metering) is a component of the SG and includes remote metering, load control, remote connect/disconnect as well as establishing a bidirectional link from the utility to each customer service point. This is more than often the first and a very important component rolled out in the SG implementation strategy. SM enables direct communication with the customer consumption metering via various communication media. The utility is able to read consumption as well as information regarding the state of the meter and basic power quality parameters like voltage levels automatically. The profile of the customer consumption can also be recorded as well the tariff updated when required. The customer on the other hand can access his consumption and billing information via the CIU (customer interface unit) or on the utility website via the internet. Many utilities also provide smart phone apps to access customer and consumption information. The basic connectivity between field device, utility and customer is thus established in this first phase of implementing SG technology. SM eliminates a number of manual processes like meter readings, disconnections, meter audits and load management. It also creates a medium for the customer to take ownership of his consumption with near real-time information.

What is the investigative process to implement SG?

SANEDI's "Smart Grid Vision 2030, March 2013" document proposes the following methodology, which provides a guideline of the processes required.

- *Vision:* What do you want to accomplish?
- *As is analysis:* Where are you now?
- *Gap analysis:* What needs to be done?
- *Strategy and road map:* How do I get there?
- Use a pilot installation to evaluate functionality
- *Business case and value position:* What will the cost and benefits be?
- *Functionalities required:* What does the system have to do for me?
- Implementations, system components, roll out and operation

Why and how utilities implement SM systems

System objectives

- *Meeting legislative requirements*

In many countries regulatory requirements motivated the switch to SM. Utilities were normally given a target date for conversion to SM systems and had to plan and implement the SM systems in their distribution operations. Some countries offered some government grants to partially fund the implementation of the required technology. The drivers for the legislation can be different in the various countries but in South Africa the main driver for the promulgation of regulation 773 of July 2008 was the shortage of generation capacity. The regulation basically requires all customers with an average consumption of more than 1000 kWh per month to be served via a smart metering system on a time of use tariff. The SM should also be able to control non-essential loads like water heaters. The main objectives were thus to reduce electricity use by implementing more efficient technologies.

- *Solve revenue/unit losses*

Many utilities in South Africa experience substantial losses in terms of technical, non-technical as well as revenue collection losses normally referred to as ATC&C (aggregate technical, commercial and collection losses). The implementation of SM enables utilities to use technology as a tool to improve the management of the losses in the value chain by improved meter reading, tamper detection, meter failure detection as well as revenue management processes supported by SM and back office computer systems. Utilities will however have to realise that the systems are merely tools and by itself cannot solve process and procedure problems. It needs to be used and managed very well to realise the required end effects.

- *Improve operational efficiency*

Many operational processes are very manual and cumbersome. By installing SM the utility has a direct view of the distribution network up to the point of service point. Traditional SCADA systems could only give an indication of the high voltage network status. Outages will be visible to operational staff via the SM and SG communication system and enable them to react timeously. The visibility of the network will also improve the outage restoration process and improve network availability.

- *Improve customer service*

Customer service normally lacks in the reliability of metering, meter reading and correct billing. Customers should be better informed regarding their consumption levels and billing information. SM could improve the service to customers.

Policy objectives

Policies will have to be developed to address the following subjects to ensure that a utility derive maximum benefit from the installation and operation of an AMI.

- *Target customer groups*

The utility should clearly define which customer groups to target with the new technology. It would not make financial sense to install highly sophisticated equipment to manage a very small consumer where the existing metering system may be more than adequate.

- *Target geographical areas*

The utility should ensure that specific geographical areas are identified for the roll-out. Most communication systems used for SM are financially more effective if implemented on higher density dwellings in a specific geographical/ distribution area.

- *Electricity tariffs for smart metering*

SM is capable of implementing TOU tariffs as required in regulation 773. Tariff policies should thus include a residential TOU tariff structure.

- *Enhance the bylaws to support the policies*

Municipal utilities should update their bylaws to allow the use of SM, TOU tariffs and remote disconnection as well as load control facilities.

Business drivers

The following business drivers should be taken into consideration when motivating the installation of a SM system and also quantified in the business case for the project. Be however very specific in your utility to address the most pressing issues first. It is hardly ever possible to solve a multitude of challenges all at once. Plan the total project but use a phased approach and concentrate on the items that will have the most dramatic effect and implement that functionality first.

- Legislative
- Operational efficiency
- Customer services
- Revenue improvement
- Loss reduction
- Cost reduction
- Energy efficiency

Cost factors

RFP/project consultancy

The planning and roll out of a SM system is no trivial task. It requires technical, project management and experiential skills. It is hardly ever possible to use your line staff to perform their daily job as well as manage a time and knowledge intensive project like SM. Seriously consider contracting an experienced company to manage your project and assist you during the SM planning and implementation process. Do this from day one. SM is probably one of the most complex systems that utilities will be implementing. It needs a multi-disciplinary approach to be successful.

Metering installation and maintenance

The quality and reliability of a SM system is heavily dependent on the correct installation and implementation of the meters in the field. Consider the cost of installing and maintaining the meters carefully. Plan the installation effectively, contract the right company for the installation job and make sure your staff acquires the correct skills in the process. You install once but maintain equipment for ten years after the initial roll out.

Communication installation and operation

An important cost factor to take into consideration is the installation, maintenance and operation of the communication system. Effective SM operation depends on a reliable cost effective communication system and one should consider the options carefully. The choice of communication systems could make or break the reliability of your SM system. Maintenance cost could escalate beyond financial viability if you have to battle to keep

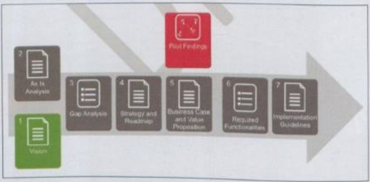
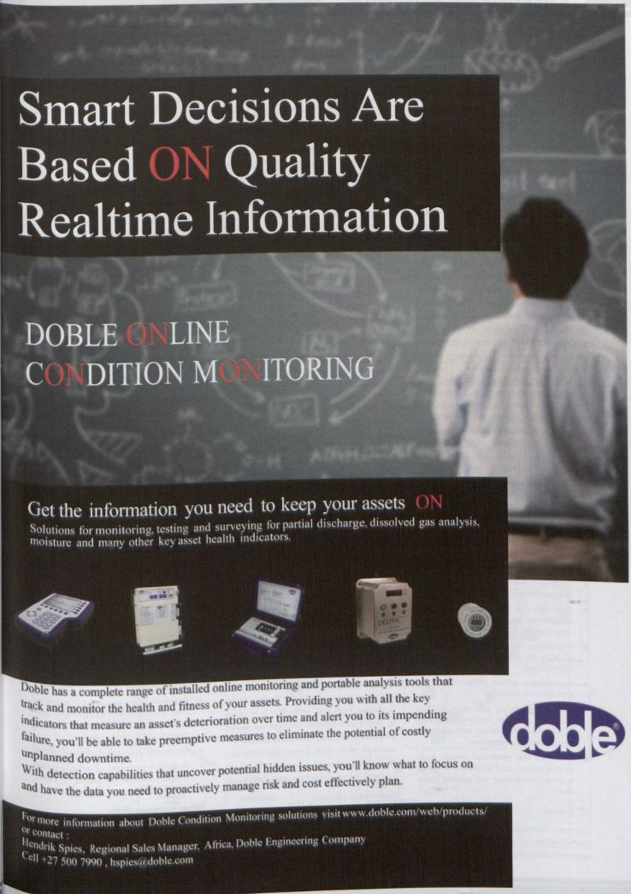


Fig. 2: SANEDI SG implementation stages.


Smart Decisions Are Based ON Quality Realtime Information
DOBLE ONLINE CONDITION MONITORING
Get the information you need to keep your assets ON
Solutions for monitoring, testing and surveying for partial discharge, dissolved gas analysis, moisture and many other key asset health indicators.
Doble has a complete range of installed online monitoring and portable analysis tools that track and monitor the health and fitness of your assets. Providing you with all the key indicators that measure an asset's deterioration over time and alert you to its impending failure, you'll be able to take preemptive measures to eliminate the potential of costly unplanned downtime.
With detection capabilities that uncover potential hidden issues, you'll know what to focus on and have the data you need to proactively manage risk and cost effectively plan.
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the system operational. Customers will lose faith in your system very quickly if it simply does not work or they receive estimated readings on a brand new state of the art system.

Back office systems and software

EIM (enterprise information management) enables raw data to be turned into information, intelligence, knowledge, and wisdom. As information systems are becoming critical to the success of business, information management must be dealt with holistically. This component can be very expensive to install and operate. Especially in smaller utilities the meter data management and analytics which is a vital part of the SM system could cost a major portion of the system investment. Many IT companies provide a cloud based service where all the complex software is available to a utility on a contract basis. The system, software and functionality are thus supported by a service provider and the utility staff can concentrate on the utilisation of the system. These systems provide the following functionality:

- Enables utilities to take ownership, responsibility and accountability for the improvement of data quality and information accuracy and consistency.
- Enables utilities to establish single version of truth for data over time.
- Improves utilities process and operational efficiency and effectiveness.
- Provides a strategy and technique to mitigate the risks as well as maximise the value of implementing commercial packaged applications.
- Reduces the number and effort of integration over time.
- Enables the control of unnecessary data duplication and proliferation.
- Enables a more flexible and scalable process integration.
- Improves the data quality, integrity, consistency, availability, and accessibility over time.
- Maximises the return on investment of SOA (service oriented architecture) technologies.
- Establishes a critical component of the Enterprise Architecture.
- Provides guidance and services, and enables consistent implementation of SOA and information management across major programs.
- Provides the essential meter data management and analytics engines required to manage and process meter data

ICT systems

Systems integration, particularly for municipalities, of many of the automated systems traditionally used by large utilities can be cost prohibitive – not only in terms of their purchase price, but in terms of the resources tied up to properly implement and support them. A municipality needs an incremental "bottom-up" way of building its smart grid – where each increment is built according to the highest business priorities while contributing to an overall long term master plan. Some form of services-driven automation is most appropriate for this situation, where each service can be owned/leased/operated or outsourced by the utility. Whether achieved through "solutions as a service" or not, the key to success will be establishing a SOA (service oriented architecture) and analytics integration infrastructure based on "non-silo" data. To achieve service-oriented integration design, technical interoperability (using standards such as Web Services) and semantic interoperability (using standards such as IEC CIM) must both be addressed.

Skilled staff

The reskilling of staff on new procedures and technology is probably the most under estimated component of implementing a successful SM system. The complexity of the new system is often not realised until it is too late and it becomes a real challenge to effectively use the new systems. Officials and customers lose faith in the new system and it could become a burden rather that a solution. Take the cost and time into careful consideration when a SM deployment is planned. Get all stakeholders involved and ensure that each person knows what is expected of them. Train and empower people to use the new system effectively. Municipalities are particularly prone to bad communication between sections and departments and this could affect the successful roll out very negatively.

Possible benefits

The following possible benefits could be realised by using SM systems. Remember however that the SM system is the tool that should be used by your highly skilled staff. Choose the functionality required by your institution and make sure that the correct processes, staff and motivation is in place to realise your benefits. Manage the system intensively by using dedicated staff. It will not work all by itself. Do not fall in the trap of throwing money at a problem, buy all the best technology and not manage it effectively.

Operational efficiency

- Improved processes
- Network visibility and upgrading
- Outage management
- Maintenance management

Customer satisfaction

- Personal energy management,
- Cost and consumption feedback
- TOU tariffs

Energy efficiency

- Peak demand and network management
- CO_2 emission management
- Reduction in energy consumption per customer

Demand response

- Optimising network load
- Energy sourcing optimised

Revenue protection

- Tamper and fraud detection
- Improved billing and revenue collection
- Non-technical loss reduction

Revenue collection

- Improved meter reading processes
- Improved billing accuracy
- Better revenue management
- Improved cash flow

Systems integration

- Improved management of information
- Improved management decision making
- Information availability to all stakeholders including the customer

How do I plan the roll out of a system?

- Get professional assistance
- Know what you would like to accomplish
- Clearly define the objectives
- Define a strategy to address the objectives
- Take all cost factors into consideration
- Ensure that you acquire proven technology from a company that will support you for the life of the equipment. SM technology has improved significantly over the last five years. You do not have to be a pioneer by buying unproven technology and risk incompatibility, supplier lock in and ineffective technology solutions
- Stick to the correct standards to future proof the system as much as possible
- Ensure that the new system is integrated into your existing system but also adaptable to any new systems you may acquire in the next ten years.
- Ensure that your staff is effectively skilled
- Acquire the services of reliable system support staff or outsource to expert companies.

What happens to my current systems

Legacy systems will have to co-exist with newer systems like SM back office and metering systems. The planning of new systems will have to accommodate older meter systems e.g. accept manually read meters, existing prepayment systems as well as financial and billing systems. One of the big challenges in the implementation of newer systems is the integration with older systems. No utility will be able to replace all existing systems in the short term.

As far as metering systems are concerned older and new SM systems can co-exist. The utility may have a strategy to retain say existing prepayment systems in entry level consumption areas. Integration of consumption and sales data can take place in the meter data management system or the billing system. Processes will have to be adapted to accommodate new and legacy systems to be effective.

SM component selection

Use proven technology

It is essential to use proven technology. So many examples of unreliable SM components can be cited and it is not necessary to re-invent the wheel. Also be aware that many eastern countries sell their products under different brand names. Ensure that you know who the actual manufacturer is. Rebranded items can easily be discontinued and components from other sources be offered.

Use a proven set of standards

Do not use systems with proprietary technology or meter system protocols. It will catch up with you and cost you dearly. Although inter-operability is still not generally possible at this stage of technology development it should be available in the near future. Any interoperability between different suppliers implementation will have to make use of proven standards. It is thus essential to support acceptable open standards in all sections of a SM system. Let your professional advisor or consultant investigate and recommend a suitable set of standards for your equipment. Although technology ages very quickly a good set of standards implemented in the SM system will ensure that older and newer technologies can co-exist A lot of work by many experts has resulted in many good and proven standards being adopted by the major standards organisations. Typical standards applicable to South Africa include the following: SANS, IEC, CENELEC, EN, DLMS/COSEM, CIM and STS.

Implementation team

Experienced project management

Use well experienced project managers. The team should include all stakeholders (departments and sections from finance to technical staff) and problems that may arise during the installation program should be addressed immediately and effectively by the team.

Experienced installation teams

Ensure that the installation teams are experienced and well trained to install and test installations in the field. Remember that these teams also interface to your customers. Make sure that they assist customers and not aggravate them.

QA processes

A well designed and managed QA (quality assurance) team is vital to ensure that the installed systems have been installed according to specifications and it is functionally sound. Rolling out large metering and communication systems without an effective QA process is a good recipe for disaster and many customer complaints.

Installation data management

Many meter installation projects have landed up in a situation where the installation data was not captured correctly. It immediately means that you do not know which customer is metered by what meter. All your billing will be incorrect and in many cases you will not

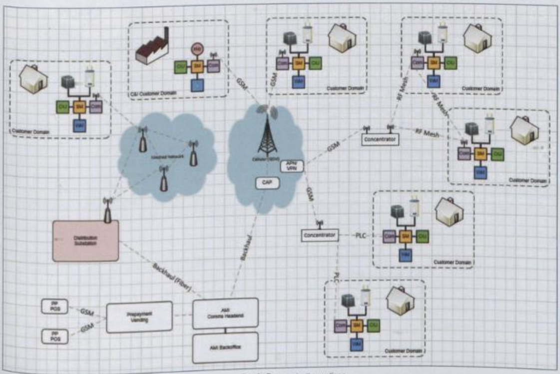

Fig. 3: Communication options.

know where the meter has been installed. This will require a costly audit to correct the meter data. Manage it from day one and ensure that your customer/meter database is clean and correct.

Risk factors

Vendor lock in due to proprietary equipment

Acquire equipment manufactured to operate on open standard communication protocols. A proprietary system will only be available from one supplier and if that supplier stops manufacturing of a particular product your installations will be at risk. Proprietary systems may also lock the utility in to purchasing equipment from only one vendor. This could prove to be a problem with municipal tender legislation.

Unreliable communication systems

Obtain communication services and equipment from proven suppliers and systems that have extensively been tested in the field.

Under-skilled personnel

Ensure that your staff is effectively trained and informed about the operation of the new system. Unskilled staff can sink your system very effectively.

Technology aging

Technology ages very quickly resulting in obsolete systems and meters long before the planned lifespan have been reached. SM systems are being improved at a significant rate. By using standardised equipment one can "future proof" systems to a large extent.

Customer acceptance

Customers are a vital link in the process to successfully implement SM systems. If customers do not experience any advantage their perception and rejection of the system can nullify any planned benefits from making a significant investment in SM. Ensure that your customers are informed and sell the customer benefits to them. The visibility of customer consumption data is of vital importance. Make it easy for customers to use and appreciate the new system.

Communication options

Smart grids and smart metering systems are highly reliant on effective and reliable data communication systems. The requirements at the various nodes and applications also vary according to the bandwidth and latency allowed at the specific nodes. Electricity protection devices for example would require millisecond response times whereas metering devices could be read and data collected at various time slots during a day.

The establishment of utility owned communication networks versus the use of external communication service providers also need some evaluation. Third party cellular and RF spread spectrum networks may be covering the total utility area. It should thus not be necessary to duplicate this infra-structure. As far as the last mile communications are concerned the PLC and radio mesh communications could be installed and owned by the utility. Once these links have been installed it will serve the purpose of establishing dedicated communication between meters and concentrators and will have no overhead operational cost apart from maintenance. The communications between meters and concentrators are to a large extent inherently part of the offering of a particular supplier and will be part of the AMI roll-out infra-structure.

For the purpose of rolling out AMI systems the following communications media will be suitable in most cases. Combinations of these technologies will be used in SM systems. Choose the most reliable and cost efficient method for the roll out of larger metering installations. The final choice of communication medium will be dictated by physical and geographical attributes and one should allow for a combination of systems to be used in a particular area. Where radio transmission is not reliable due to building construction or interference from nearby radio transmission devices PLC may be the better choice. PLC on the other hand may be unreliable due to noise introduced on the electrical network generated by industrial devices and installations.

Technology ages very quickly and systems deployed will have to allow for the upgrade of the data communications devices used in a particular installation. Meters should have a service life of ten to 15 years but communication and networking will change significantly during this period. An effective strategy to future proof communications assets will have to be deployed. The adoption of very stable standards are normally the only methodology to ensure that technology survives the technology development phases and provide financially viable service before it will be phased out. It is also a fact that a utility will have a combination of older and newer technologies installed in the field. These installations will have to be compatible to provide a seamless AMI system.

- Cellular (wide area).
- RF mesh (short distance).
- PLC (short distance).
- Radio spread spectrum (wide area network).
- Fibre optics (dedicated WAN links).

Security

The European Network and Information Security Agency (ENISA) report "Smart Grid Security – Recommendations for Europe and Member States"[1] also recommends a broader context. A summary of enterprise level recommendations inlcudes:

- Consider cyber security and privacy as a vital part of your system implementation.
- Security efforts should not only include smart meters.
- Security training of operations staff and consumers.
- A set of standards and guidelines that includes (among others):
  - Reference risk assessment methodology
  - Methodology for assessing interdependencies
  - Incident handling strategy
  - Establish security governance
- Consider cyber security in all domains and phases of the system lifecycle.

Conclusion

The planning and implementation of SM systems requires experience and knowledge of the systems and standards in the industry. It is also essential to select appropriate technology to ensure compatibility with future as well as existing and legacy systems. Utilities should embark on this road with caution. Compile a cost benefit analysis and ensure that the utility implement functionality where the maximum benefit can be derived for the supplier and the customer. Ensure that your staff, customers and all the utility stakeholder form part of your implementation team. The success of a SM system roll out depends on co-operation between technical, financial, ICT and management. Manage the risks, quality and functionality of the new system effectively to operationalise information to the advantage of the utility.

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Note 1: Additional details of the recommendations is provided in Annex B.2 ENISA Recommendations.

Revenue protection success story: The River Park (Alexandra) case study

by Xolani Lembede, City Power

Due to low level of payments in low income areas, City Power has been experiencing high levels of electricity theft, network overload and a high rate of repeated failures. The ultimate solution to the problem is to educate customers about the benefits of paying for services and the consequences of abuse and theft of electricity. The experience has however proven that it is human nature that once you have experienced free services, you develop a sense of entitlement and it becomes difficult to adapt to paying for those similar services.

Authorities have to strike a balance between the electricity usage and by-law enforcement. The utility has to recoup the consumption related costs, protect the infrastructure from vandalism and monitor the consumption patterns for the purpose of detecting theft. However, all the efforts will only succeed with the community's buy in, hence the importance of vigorous community awareness initiatives.

Background

Alexandra is one of the oldest townships in Johannesburg. The development of this township dates back to 1912 and has a very rich South Africa history [1].

Alexandra is divided into a number of townships mostly with ancient types of dwellings, but the Alexandra Renewal Project (ARP) has introduced new townships with clearly demarcated stands. The article will discuss the River Park Township portion of the project.

River Park Housing Project, Johannesburg, South Africa

As a consequence of the new political dispensation in 1994, the Johannesburg City Council embarked on a project to construct "top structures" (buildings) on already proclaimed and serviced land designated for housing.

This particular development was called River Park and was located just across a tributary of the Jukskei River from the established suburban area of Lombardy East, and on the east bank of the river opposite traditional Alexandra Township. In the first phase of the proposed 700 family scheme, 150 units were built and occupied. Figs. 1 and 2 indicate the serviced dwellings of phase one.

The houses are a combination of RDP and the walk ups type dwellings, well orientated and provided good quality exterior space in the landscape whilst contributing to an active streetscape. Maximum internal volume was achieved within the limited budget constraints, giving a sense of lightness and scale. The proposal demonstrates that low-cost, high-density housing can be built with sensitivity to good design [2].

Fig. 1: Serviced River Park houses [2].

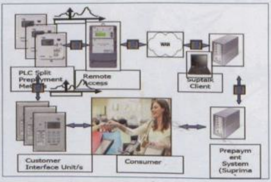


Fig. 3: Prepaid system process flow [3].

Fig. 2: Typical houses in River Park [2].

Band	Frequency	Application
-	3 to 9 kHz	Utility use only
A	9 to 95 kHz	Utility & Licensee use
B	95 to 125 kHz	Consumers (unrestricted)
C	125 to 140 kHz	Consumers with MAC
D	140 to 148.5 kHz	Consumers (unrestricted)

Cashpower meters PLC2 = 66 kHz

Fig. 4: PLC meter operating frequency band.

Revenue enhancement project

City Power recently embarked on an extensive revenue enhancement project in Alexandra Township. This report focuses on the River Park Section, where the vast majority of electricity meters were tampered with and bypassed, resulting in extensive revenue losses and frequent power outages for City Power.

The original metering system was not STS compliant, leading to the residents protesting against the devices usage to meter their consumption. The infrastructure was vandalised, giving access to rouge elements resulting in collapse of some revenue collection mechanisms.

Solution

The solution talks to the number of interventions to prevent theft and estimations. Fig. 3 indicates the process flow of the solution.

Meters

All residential electricity meters in this area were replaced with Power Line Carrier (PLC) prepaid meters, which are housed and secured in protective meter enclosures.

These are simple PLC2 meters with proven FSK technology (IEC 61334-5-2) for cost sensitive split prepayment metering solutions (IEC 62055-32). The meters are made according to Cenelec A band frequencies and CISPR 22 maximum signal levels with protocol using a single carrier frequency of 66,0 kHz as indicated in Fig. 4. This A band frequency is reserved solely for use by utility equipment, and it is ideal for low cost communication [3].

Current challenges with the meter

- Compliance with Cenelec EN50065-1 limits the transmitted signal strength.
- The technology relies on good line conditions to avoid blocking from narrowband sources emitting at the same frequency.
- Interference from appliances can however swamp the Cenelec compliant signals.

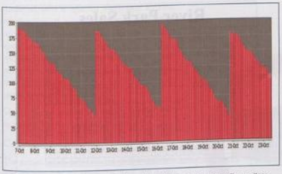


Fig. 5(a): Data concentrator reading with healthy meter consumption pattern.

Fig. 6(b): Data concentrator indicating all meters.

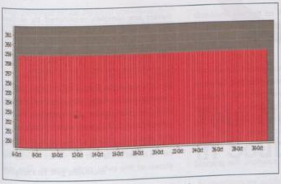
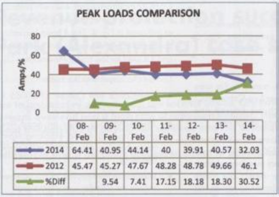


Fig. 5(b): Meter in tamper mode.

Fig. 7: Protective enclosure unit.

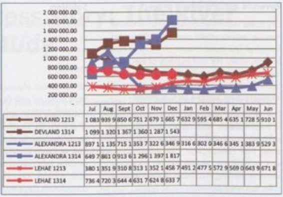
Fig. 6(a): Data concentrator indicating one faulty meter.

Fig. 8: Protective enclosure unit with meters inside.



	08-Feb	09-Feb	10-Feb	11-Feb	12-Feb	13-Feb	14-Feb
2014	64.41	40.95	44.14	40	39.91	40.57	32.03
2012	45.47	45.27	47.67	48.28	48.78	49.66	46.1
%Diff		9.54	7.41	17.15	18.18	18.30	30.52

Fig. 9: River Park load patterns before and after intervention.



	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
DEVLAND 1213	1 083	939 9	850 6	751 2	679 1	665 7	632 9	595 4	685 4	635 1	728 5	910 1
DEVLAND 1314	1 099	1 320	1 367	1 360	1 287	1 543						
ALEXANDRA 1213	897 1	1 135	715 1	353 7	322 6	346 9	316 6	302 0	346 6	345 1	383 9	529 3
ALEXANDRA 1314	649 7	861 0	913 6	1 296	1 397	1 817						
LEHAE 1213	380 1	351 9	310 8	313 1	352 1	458 7	491 2	477 5	572 9	569 0	643 9	671 8
LEHAE 1314	736 4	720 3	644 4	631 7	624 8	633 7						

Fig. 11: Year on revenue growth after intervention.

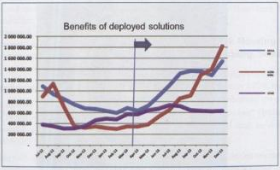


Fig. 10: Continuous revenue growth after intervention.

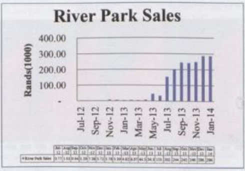


Fig. 12: Revenue impact.

- Such interference sources are managed via the application of narrowband PLC filters and/or by enforcement of by-laws insisting on consumer appliance compliance with the Cenelec norm.

Data concentrator/remote access terminal (RAT) unit

PLC Data Concentrators were installed at each mini-substation or adjacent to each pole mounted transformer which remotely monitor the prepaid meters and provide City Power with a wealth of meter data information, including events such as tamper, mini-sub power failure, as well as a host of additional data to assist the utility in managing the prepaid meter park.

The PLC Data Concentrator constantly monitors the PLC communication between the PLC prepaid meters and their keypads, collecting profile data, such as meter consumption, and immediately reporting critical pre-configured meter events such as tamper.

Using this innovative solution, the prepaid meters are remotely monitored by skilled staff at the City Power Nerve Centre and should a meter be reported as tampered with, personnel are immediately dispatched to investigate and rectify the situation.

Fig. 5(a) shows the data concentrator reading showing healthy meter consumption pattern, and Fig. 5(b) shows the graph with an indication of a tampered meter mode.

Fig. 6(a) shows the data concentrator at the centre of the circle and the meters monitored shown at the outer circle around. The red meter icon helps the utility to easily identify the tampered meter(s) that require further investigation. Fig. 6(b) is the data concentrator indicating all healthy meters.

Metering protective enclosures

To avoid electricity theft and tampering with meters, City Power has resorted to measures to prevent public access to the meters. The protective structures are a method becoming more popular in utilities because of its effectiveness in preventing access to electrical installations and specifically energy meters and LV circuit breakers. These enclosures have strict access control features to prevent unauthorised entry.

The structure is made out of a thick mild steel material with a special electronic locking mechanism. It is manufactured with built-in sensors that will sense vibration and forced entry which will trigger alarms to a remotely manned system, enabling the utility to take appropriate action. Figs. 7 and 8 show the closed and opened enclosures with pre-assembled meters.

Due to the success of this solution, City Power is rolling it out to additional sites.

Community engagement

The project experienced huge resistance from the community as residents had not been paying for electricity for a long time.

The utility had to use the local communication service provider who understands the dynamics of the area and people behaviour. The service provider had to go door to door to assess the status and advise the residents accordingly. This helped a big deal in project acceptance as the community saw themselves as part of the project and understood the benefits. Mass communication had minimal results compared to the door-to-door strategy. Residents feel that personal touch and are able to share their personal experiences and challenges.

Impact of the solution

There are two elements to the impact of the solution – the loading impact and the financial impact.

Loading impact

Assuming standard network configuration, City Power has seen a significant decrease in loading, which can be attributed the user's reaction to electricity cost. Fig. 9 indicates an average of 16% load reduction between February 2012 and February 2014. This is also evident in the significant reduction of the number of outages in the area.

Financial impact

City Power has seen positive spin-offs on the electricity revenue. Again this shows the effectiveness of the system as it is becoming more and more difficult to tamper with the system. Figs. 10, 11 and 12 indicate the revenue step change after the intervention in different areas.

Conclusion

The culture of non-payment attracts some strange electricity consumption behaviour, but not because the household dwellers have lots of appliances. The dwellers start seeing business opportunities because of free services. Most of these individuals are not the real business owners within their premises but they use electricity as a tool to attract tenants who end up using rented premises as business space. The simplest solution in these problems is to enforce the by-laws and implement theft monitoring systems with strong back office energy management. Public awareness through community engagements play a big role in infrastructure safeguarding and ownwership.

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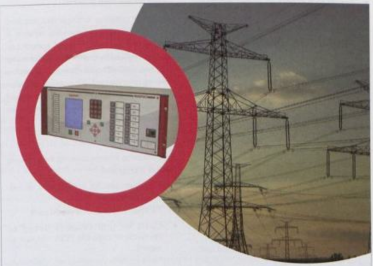

Net-metering concept for small scale embedded generation in South Africa

by Dr. Markus Pöller, Möller & Pöller Engineering

During meetings in the offices of SALGA with AMEU as a reference group on 25 July 2013 and 7 November 2013, possible options for a legal and technical framework for the connection of rooftop PV systems in South Africa have been discussed.

The net-metering concept is proposed on the base of these discussions. The following main aspects should be considered, as standard conditions for small scale embedded generators:

- Ensure safety of operating personnel.
- Ensure that impact on power quality in local distribution networks is low.
- Low administrative overhead so that private customers can also participate in it.
- High security of investments into small scale embedded generators (mainly rooftop PV systems).
- Export tariff that provides sufficient incentive to avoid illegal connection of small scale embedded generators.
- Export tariff that is sufficiently low for not creating an additional burden to overall electricity costs.
- Tariff that provides an incentive for timely generation of electricity.
- Low overhead costs for additional equipment, such as meters etc.
- Fair coverage of costs of grid usage.

This paper is to be seen as a proposal and not as binding document.

Background: net-metering

Net-metering concepts are used widely on international level for remunerating rooftop PV systems, e.g. in the USA, Morocco and Brazil [1], and in the Philippines [2].

Unfortunately, there is no generally applicable definition of the term "net-metering". Therefore, some definitions are required for explaining the meaning of "net-metering" in this document.

In this document, the term net-metering is referred to a tariff scheme having the following characteristics:

- The tariff scheme is applicable to a local generator-load combination only (and not to a generator without load, or to configurations where generator and load are installed remotely).
- A net-metering client is still considered to be a consumer and not a generator.
- A net-metering client can export and import electrical energy.
- Tariffs for export and import can either be the same ("classical net-metering", e.g. USA) or different (e.g. Philippines, Germany).
- Over a billing cycle (e.g. one year) the remuneration of exported electricity is capped to the value of imported electricity (no net payment possible).

The actual metering arrangement required for implementing a net-metering scheme is depicted in Fig. 1. The actual meters can either be realised by one bi-directional meter or by two unidirectional meters. With such a metering arrangement, it is possible to assign individual tariffs for net-export and net-import of energy and hence creating an incentive for timely delivery of electricity.

Proposed concept

A net-metering scheme covering the following aspects is proposed:

- Maximum size for applicability of net-metering is equal to 100 kVA.
- Fix import tariff and fix export tariff.
- Costs for grid usage is based on connection capacity (kVA, import or export).
- Net billing cycle is one year.
- Obligation of the grid operator to take the exported energy (under normal operating conditions).
- Guaranteed export tariff for a duration of at least three years.
- Technical rules for interconnection: no application of the grid code for renewable generation, but introduction of a simple set of rules for the installation of net-metering systems based on NRS 097-2-3.

This list represents at the same time the relevant parameters that must be defined for finalising the concept. An overview of proposed settings of the relevant parameters is shown in Table 1.

Discussion

Applicability

An absolute limit of the applicability of net-metering should be foreseen. In any case, only installations having a connection to an LV grid should be entitled to use the net-metering schemes. All other connections should be treated as generators, irrespective of the associated load.

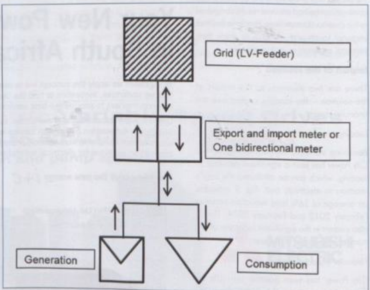

Fig. 1: Bi-directional metering arrangement for net-metering.

The working group has confirmed 100 kVA as reasonable limit, at least during an initial phase until relevant experience with small scale embedded generators could be gained.

In the medium to long term, this limit could potentially be increased to 1 MW/1 MVA because this is at the same time the maximum installed capacity with an LV connection (directly at the transformer station).

The limit of 100 kVA will probably not allow larger rooftop PV installations on commercial buildings such as offices, hotels or supermarkets to participate in the net-metering programme. These installations would still require a NERSA generator license. On the other hand, net-metering could be a very interesting option to these users because of their positive correlation between solar generation and consumption.

It is also possible that larger installations will be artificially split for not exceeding the 100 kVA limit, which is also not in NERSA's interest.

Additional limitation of the size of a rooftop PV installation, e.g. limiting the installed capacity to peak demand, as it is practiced in other countries (e.g. USA), is not required here, because the fact that export tariffs are below import tariffs will make installations

Proposal	Discussion	Ref.
Applicability of net-metering to installations with an installed capacity <100 kVA and LV connection.	Applicability of net-metering must be limited. Actual limit to be discussed. 100 kVA limit seen as an initial limit until initial experience with small scale embedded generators could be gained. Could be increased afterwards (e.g. up to 1 MVA). Small scale embedded generators having an installed capacity greater than the defined limit will automatically be treated as generators (requiring a NERSA license), irrespective of the associated load.	3.1
Bi-directional (or two unidirectional) meters.	Required for net-metering with different export and import tariffs.	3.2
Fix import and export tariff, time of use tariff is possible but cannot be mandatory for net-metering users.	Fix tariffs are simple to apply and don't require special metering equipment. Return on investment can easily be predicted. Low administrative overhead. No smart meter required.	3.3
Export tariff below import tariff.	Incentive for timely export of electricity (e.g. through storage, timely operation of heating systems etc.) automatically provided. Export tariff should not be too low because it represents an incentive for legal connection, which could get lost in case of too low tariffs. Shall be a fair value, e.g. can be defined in-line with the usual purchase price of electricity of the distribution utility.	3.3
Net billing cycle of one year.	Net billing cycle should at least be one year (across all seasons) for ensuring that electricity generated in summer will be fully remunerated (e.g. high summer production balanced off by lower production in winter). Net billing cycle >1 year will probably have implications with regard to tax declarations.	3.3
Obligation of the DU to take the exported energy und normal operating conditions.	Investment security (bankability). Subject to technical feasibility of the installation, which must be evaluated prior to connection, during the application process and must not be withhold unreasonably.	3.6
Guaranteed export tariff for a duration of at least three years.	Ideally, the guaranteed export tariff should cover the entire pay-back period of the small scale embedded generator but this is not feasible according to existing legislation. Long guarantee required for investment security (bankability). Duration of three years turned out to be the maximum possible guarantee period according to current legislation (to be verified by legal advisors).	3.3
Costs of grid usage should be on kVA basis and should cover network management and administrative services of DU.	Import tariff (kWh) must be reduced correspondingly for not increasing overall cost of electricity. Total cost of electricity of a user with average consumption must not increase when switching over to a net-metering tariff (without considering generation). In other words: energy produced by small scale embedded generator will always lower electricity bills, even if generation is very small. Exaggerated fixed charges for grid usage basis would endanger economic viability of most rooftop PV projects. Exaggerated fixed charges lead to low variable charges (cost of energy/kWh) and therefore create an incentive for high consumption (and reduces the incentive for energy efficiency measures). Too low fixed charges could endanger the economic viability of DUs. Grid usage on kWp basis (instead of installed kVA) would create an additional incentive for timely generation/consumption/installation of storage but would require smart metering and have therefore not been considered by the working group.	3.4
Technical rules for interconnection of net-metering systems.	One document focusing on safe installation, safe operation and avoidance of negative impact on power quality (basis: NRS 097-2-1). No application of the rules and procedures described in the grid code for renewable generation, which would be too complex for small scale embedded generators.	3.4

Table 1: Discussion of proposed net-metering scheme.

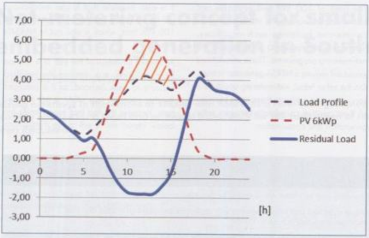

Fig. 2: Load, generation and residual load profile.

(which are much larger than the associated load) unprofitable.

Metering arrangement

Since the proposed concept for small scale embedded generation foresees an export tariff which is different from the end-user/import tariff, the metering setup must explicitly distinguish imported and exported energy according to the following definition:

- Import: Local load ≥ local PV generation => residual load ≥ 0
- Export: Local PV generation > local load => residual load < 0

This can be realised either by two unidirectional meters or one bi-directional meter with two separate registers (import and export register), as shown in Fig. 1.

Tariff

From a costumer/investor perspective, net-metering, in combination with a rooftop PV system, is economically viable when there is a return of investment within an acceptable period of time. This depends on investment costs, produced energy, electricity tariff and the tariff considered for exported electricity.

Initial expenditure mainly consists of investment for the PV modules and inverters, with additional cost for its installation.

If the remuneration concept uses an export tariff which is below the end-user tariff, the incremental earnings per kWp will decrease when the locally generated energy exceeds local consumption during some times of the day. This will basically always happen in the case of residential consumers, whose load can easily drop down to almost zero during mid-day, when nobody is at home. However, in the case of commercial end-users, demand and PV-generation are much better correlated and therefore, a PV system can be sized so that the complete energy produced can be used for self-consumption (at least on working days).

These considerations lead to the following conclusions with regard to the proposed tariff scheme:

- The proposed tariff scheme provides better incentives for commercial end-users than for private users.
- The proposed tariff scheme provides an incentive for timely use of energy (e.g. heating warm water tanks/swimming pools etc. during midday and not during evening peak) without the need for special time-of-use tariffs.
- The proposed tariff scheme will automatically limit the size of rooftop PV installations to the size of the corresponding load, which will automatically reduce or even avoid grid problems relating to situations with high power reversals (e.g. high voltages during high power exports).

Besides the actual value of the export tariff, the following aspects should be considered for enabling bankability of rooftop PV-investments:

- Export tariff should ideally be fixed over a period equal to the pay-back period of the small scale embedded generator.
- The grid operator must be obliged to take and remunerate the exported electrical energy under normal operating conditions during the same period.

Without these two criteria, the required investment security wouldn't be given and the bankability of rooftop PV systems would be endangered.

Grid usage

For residential users, grid usage is usually paid on a kWh basis, even if in reality, grid-dependent costs depend on the installed connection capacity (in kVA) instead of energy loads (in kWh).

In a net-metering concept, when used in conjunction with a kWh-only tariff, every kWh of electricity which is generated by a small scale generator (i.e. PV) reduces the cost of grid supplied power – but because the PV system (without storage) does not actually reduce the maximum power consumption, the full grid capacity is not reduced.

This justifies a tariff scheme in which the grid usage is paid for in a kW or kVA basis and not a kWh basis. On the other hand, such a tariff scheme considerably reduces the economic viability of most small scale embedded generators. Therefore, the connection fee (on kVA basis) must be carefully defined for not endangering the economic viability of small scale embedded generators.

When deciding on the actual tariff, the following aspects should also be borne in mind:

- Introducing a fixed component in the tariff (kVA basis) requires lowering the variable part (on kWh basis) of the tariff. Otherwise, overall cost of electricity would increase, which could not be justified.
- The tariff for net-metering users (fix/variable charge) should be configured in a way that for a user with average consumption, cost of electricity doesn't increase when switching over to a net-metering tariff (even without any credits for generated electricity).
- The fix tariff component must be sufficiently high for covering the DU's expenses for grid services and administration.
- On the other hand, it has to be considered that high fixed charges lead to lower variable charges, which in turn reduces incentives for investments into increased energy efficiency.

Hence, the decomposition of residential tariffs into fix/variable components require careful balancing and it is recommended that every net-metering tariff will have to be approved by NERSA.

Technical rules for grid connection

Currently, there are two standards or guidelines in place that apply to small scale embedded generation:

- NRS 097-2-1:2013.
- NERSA Grid Code for Renewable Generation [3].

From a legal point of view, the NERSA grid code is a much stronger document, because it is legally binding.

However, its applicability to small scale embedded generators is very low and its technical requirements are not complete (e.g. with regard to safety or protection aspects). Besides this, compliance validation procedures proposed by the NERSA Grid Code for Renewable Generation [3] are by far too complex for small scale embedded generators and require engineering services that would probably cost more than the entire installation.

For this reason it is proposed to define a separate document named "Technical Rules for the Interconnection of small scale embedded generators in South Africa", in which all required technical rules and compliance procedures are described. Such a document should include the following aspects:

- General requirements for electrical installations in South Africa (with reference to the applicable standards).
- Guidelines for the installation of net-metering equipment (arrangement of breakers and disconnectors, protection-related aspects, metering arrangement).
- Voltage and frequency ranges of unrestricted operation.
- Power quality aspects.

These technical rules should be based on NRS 097-2-1:2013, which are very well elaborated, but in some parts not sufficiently specific to the South African situation.

Investment security

Experience in other countries has shown that investment security is a key factor to the success of a regulatory framework for renewable energy projects.

For this reason, it is important that:

- It is ensured that a DU cannot decrease the export tariff during a guaranteed period. This period should ideally be in-line with the pay-back period of a rooftop PV-installation.
- The distribution network operator is obliged to take the exported electricity under normal operating conditions during the same period.

Without these aspects, the benefits of net-metering would be substantially reduced.

Conclusion

This document proposes a remuneration scheme for small scale embedded generators <100 kVA and LV connection (in particular rooftop PV systems) in South Africa.

It addresses a series of issues that were discussed during meetings of representatives of municipalities, Eskom, AMEU, GIZ and its consultants hosted by SALGA on 25 July 2013 and 7 November 2013 in Pretoria.

The proposed approach is based on an advanced net-metering concept considering different tariffs for net-export and net-import of electrical energy.

The document should provide an input into the decision-making process and indicate possible solutions for the various issues and problems that distribution utilities may face when introducing such a concept.

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Impact of the new health and safety regulations on electrical engineers

by Dr. Willem du Toit, SAFTEK Technologies

Municipal engineers and in particular electrical engineering staff have traditionally seen health and safety (H&S) as two separate managerial entities: H&S management and H&S compliance. They also perceive H&S responsibilities as separate functions which H&S management departments are solely responsible for, and view H&S management as more closely associated with occupational health and environmental management and the compliance thereof, than with engineering. Most municipal electrical engineers perceive their electrical engineering responsibilities as ensuring the safety of staff during maintenance and construction activities only.

However, the new construction regulations require electrical engineering staff and other engineering departments, including the appointed town engineer (who is a competent person in terms of the General Machinery Regulation 2 of the Occupational Health and Safety Act), to be professional construction health and safety agents (Pr CHSA) and to become more involved as the client representative in the interaction with design engineers, procurement and appointment of contractors and advisors on H&S (Defined agents for H&S). The construction regulations defines "construction work" (in terms of municipal electrical activities) as any work in connection with the erection, maintenance, alteration, renovation, repair, demolition, dismantling of, or addition to a building or structure and the installation, erection, dismantling or maintenance of a fixed plant (switchgear, power lines, cables etc.).

The process to follow for both maintenance activities and projects in electrical reticulation work requires that a baseline risk assessment be made before any design or planned maintenance activities take place. Such baseline risk assessments should indicate the risks and mitigation procedures which must be developed. In terms of designs for construction projects, such baseline risk assessments must be included in a site specification which is specific to the planned project. This will then be forwarded and explained to the designers. Not only are town engineers advised to make use of registered Pr CHSA agents, but they are also forced to employ such agents in terms of the new construction regulations for certain projects. It is advisable that only agents who are registered with the South African Council for Project and Construction Management Professions (SACPCMP), and who have a background in electrical engineering, be used. A person without an electrical background would not be able to give advice on specific processes or understand the dangers involved in low, medium and high voltage switching or working on or near live electrical installations.

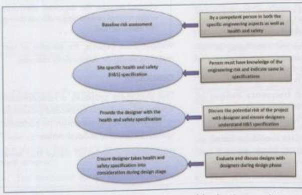

Fig. 1: The role of designers and the client in new projects.

Town electrical engineering and consulting engineers

To ensure full compliance with the new construction regulations, an understanding of the requirements and procedures of the new construction regulations is imperative to electrical engineers and designers of town electrical engineering reticulation networks. According to the new construction regulations, the designer is defined as a "competent person" who prepares checks, approves a design and includes an engineer contributing to, or having overall responsibility for, a design.

Electrical design engineers' responsibilities, in terms of the new construction regulations, now extend beyond mere involvement in the design phase, but also include responsibility for ensuring safe construction and installation of their designs as well as the usage and maintenance procedures of their designs. Design engineers' role and accountability for their designs in terms of risk that their designs may pose, include interaction with health and safety professionals and certification of their work.

Although the responsibility for ensuring H&S during the construction phase is largely the responsibility of principle contractors, specific specialists and subcontractors must also ensure correct installation and, in the case of certain low voltage electrical installations, certification according to the specific OHS legislative regulations and safety standards, or codes of practice. The design engineer, overall, must ensure that required, specific method statements and procedures are available for the safe installation of designed projects. Practical examples would include electrical switching procedures related to the commissioning of new electrical equipment and reticulation networks.

Method statements for the safe installation of services are not generic but specific to job tasks which are not routinely conducted. Such tasks are usually in a maintenance and construction environment which, due to the nature of new work, requires guidance on specific procedures. Procedures may include a manufacturer's installation methods and acceptable written engineering practices or international and local safety standards. Design engineering is to advise on correct and safe methods to install specific plant equipment and installations, and to ensure that the procedures followed do not increase the risk of injuries but rather mitigate any risk identified. Designers therefore need to take cognisance of the fact that an incorrect method statement can be used against them in legal proceedings.

Electrical engineers, consultants and in-house designers involved in the design of town electrical networks are responsible for the following, according to Construction Regulations 6:

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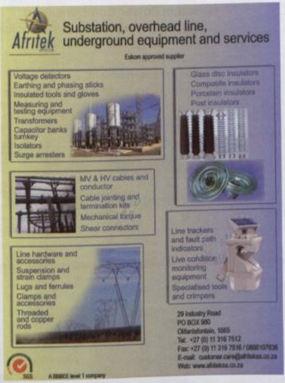
- To ensure that the applicable safety standards incorporated into the construction regulations and applicable regulations are complied with in their designs (e.g. SANS 10142).
- To take into consideration the health and safety specification submitted by the client, before a contract is put out to tender, and make available in a report to the client all relevant health and safety information about the design and installation of the relevant structure that may affect the pricing of the construction work.
- To inform the client in writing of any known or anticipated dangers or hazards relating to the installation and construction work of their design, and make available all relevant information required for the safe execution of the work they designed, or any subsequently altered designed work (this includes safe work procedures for their specific installation).
- To refrain from including anything in their design that requires or necessitates the use of dangerous procedures or materials, hazardous to the health and safety of the persons doing the installation and construction work, which can be avoided by modifying the design or by substituting materials.
- To take into account the hazards relating to any subsequent maintenance of the relevant structure or installation and make provision in their design for that work to be performed, in order to minimise the risk of future maintenance activities required.
- When given a mandate by the client to carry out the necessary inspections at appropriate stages to verify that the construction and installation of their designs are carried out in accordance with the design's specifications; if the designer is not so mandated by the client, the client's agent, (e.g. professional health and safety agent – Pr CHSA) will be responsible to carry out such inspections
- The designer or the client's agent (e.g. Pr CHSA) must stop any contractor from executing any construction work which is not in accordance with the relevant design's health and safety aspects: provided that if the designer is not so mandated, the client's appointed agent must stop that contractor from executing that construction work.
- When mandated by the client, the designer must do a final inspection of the completed structure in accordance with the National Building Regulations and include the health and safety aspects of the structure. Then, as far as is reasonably practicable, declare the structure safe for use and issue a completion certificate to the client and a copy thereof to the contractor.
- The designer must, during the design stage, take cognisance of ergonomic design principles to minimise ergonomic related hazards in all phases of the life cycle of the structure.



Maintenance of town electrical networks

From baseline risk assessments provided by the town electrical engineer, in the form of a site-specific health and safety specification (usually prepared by the client's agent – Pr CHSA) designers should be capable and able to analyse risks involved in their design for future maintenance purposes, and ensure that their designs afford and mitigate risk as far as reasonable practical. They also need to provide procedures including method statements for correct H&S installation and maintenance of their designed electrical installations, switchgear and reticulation networks.

In respect of preventative planned maintenance or reactive maintenance on municipal electrical infrastructures, electrical town engineers must ensure that detailed risk assessments have been made for each anticipated job task, accompanied by specific methods and procedures (method statements) on how to perform the specific job task safely.

Such procedures will, according to the risk identified, include risk mitigating procedures (safety plans) on how to perform such task safely, including administrative procedures, engineering methods and the type of personal protective gear and equipment required for specific tasks.

Responsibilities of the town electrical engineer (the client)

Representing the client as the responsible person in terms of the General Machinery Regulations 2, the town electrical engineers', responsibilities have expanded dramatically in the new construction regulations, and it would be advisable for town engineers to seek assistance from professional health and safety agents not only with new projects but also to ensure that maintenance activities comply with the new construction regulations. Such professional health and safety specialists must be selected based on their knowledge and experience related to electrical engineering projects and maintenance, not only related to their legislative knowledge but also their engineering knowledge of the specific project.

In terms of the new construction regulations, town engineers, as the client, are force to appoint and make use of Pr CHSA agents. The town electrical engineer or appointed Pr CHSA agent (client) is responsible for:

- The preparation of a baseline risk assessment for an intended work.
- Preparing a suitable, sufficiently documented and coherent, site-specific health and safety specification for the intended construction work, based on the baseline risk assessment.
- To provide the designer with the health and safety specification.

- To ensure that the designer takes the health and safety specification into consideration during the design stage.
- To ensure that the designer carries out all responsibilities required in the construction regulations.
- To include the health and safety specification in the tender documents.
- Where changes are brought about to the design or construction work, to make sufficient health and safety information and appropriate resources available to the principal contractor to execute the work safely.
- Where additional work is to be performed as a result of a design change or an error in construction due to the actions of the client, the client must ensure that sufficient safety information and appropriate additional resources are available to execute the required work safely.
- Where a construction work permit is required as contemplated in Construction Regulation 3(1), the client must, without derogating from his or her health and safety responsibilities or liabilities, appoint a competent person in writing as an agent (Pr CHSA) to act as his or her representative.

Interaction and role of profesional health and safety agents

The introduction of a professional advisor for health and safety heralds a new era where H&S is not merely seen as compliance with administrative and legislative standards, or the advice and management by non-technical people on aspects of electrical construction and maintenance activities, but the real input by people that would have the knowledge, qualifications and experience of engineering concepts to understand real electrical engineering threats and the impacts on electrical workers' health and safety.

Although concepts of safety engineering, process safety and the professionalisation of engineers who specialise in the interaction of human safety environments are not that well established in South Africa, the formation and regulation of people with proper knowledge of the built environment, including electrical engineering, with an understanding of engineering principles, will assist in the decrease of electrical engineering- related incidents. The registration of this entity by South African Council for the Project and Construction Management Professions the (SACPCMP) will address the shortage in this field of safety engineering in South Africa.

Conclusion

Town electrical engineers need to comprehend the following: the impact that the new construction regulations will have on their town engineering operations, the role and need for proper H&S specifications, as well as the interaction and function of Professional Construction Health and Safety Agents (who are registered with the South African Council for the Project and Construction Management Professions or SACPCMP).

Electrical town engineering in both construction and maintenance activities poses unique risks which require proper interaction with H&S management systems and an understanding (from an electrical engineering point of view) of risks related to electrocutions, electrical arch flash burns and electrical burns. Furthermore, an understanding of electrical engineering risks and concepts such as mechanical, pressurisation, capacitance discharge, induction, equal potential bonding and the need for engineering and personal protective equipment, to name a few, are required. Specific fall prevention programmes (and the procedures to be followed in isolation) and permit systems which are of utmost importance to prevent injury of engineering staff, contractors and the public will ensure the H&S goal of zero harm during town electrical engineering, construction and maintenance activities.

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Substation accident: a case study

by Barry Gass, High Voltage Training

An authorised person received an electric shock and was badly burned when testing for voltage, at the back of an isolated 11 kV circuit breaker, in a substation. The authorised person died three days later in hospital from the injuries he sustained in the accident. His assistant survived the incident, escaping with burns to his hands, face and upper body. This paper is a case study and looks at the incident, causes and what could/should have been done to prevent the accident.

An authorised person had to isolate an 11 kV cable in order to cut in a new mini substation (MSS), between a substation (S/S) and an MSS. He had already switched, isolated, tested and earthed the cable on both sides correctly.

A risk assessment had been conducted and a work permit issued, in accordance with the company's rules and regulations. A work permit is defined as a written authorisation for work to be carried out on electrical mains or apparatus.

The circuit breaker (CB) had integral earthing and had been tested and placed in the earth position, locked off and a danger tag applied. During the course of the work, the authorised person had to remove the back cover of the panel (cable end box) to disconnect the 11 kV cable.

The authorised person chose to identify the correct back cover to be removed by counting the number of breakers from the left hand side.

He walked around the back of the panel, from the right, and counted the breakers from the right hand side, instead of from the left. The authorised person also checked the label on the back of the panel to confirm that he was at the correct breaker. Unfortunately, this cover was a removable cover and had been incorrectly replaced on the wrong panel during a previous job that had been done.

As the cable was earthed at the MSS and the circuit breaker at the front of the panel by integral earthing, the authorised person decided that it was not necessary to wear a flash suit when removing the back cover and testing.

He removed the back cover and decided, as an extra safety precaution, to safety test the conductors before removing the tape from the conductors. He decided to use a live tester to penetrate the insulation before removing the tape for safety. However, instead of using an approved medium/high voltage live tester, as required in terms of the company's regulations, he picked up a low voltage multimeter to test for the presence of voltage.

He also enlisted the help of his assistant to hold the multimeter, while he tested the conductors. The assistant was not wearing any special PPE (flash suit). On penetrating the tape, there was an explosion, causing third degree burns to 80% of his body and his assistant sustained burns to his hands, face and upper body.

Cause of the incident and injury

- The cover on the back of the panel had been replaced on the wrong panel the last time that work had been carried out.
- The authorised person counted from the wrong side when he went around the back of the switchgear.
- The authorised person used the wrong tester to test that the cable was dead.
- The authorised person was not wearing a flash suit whilst testing that the cable was dead.
- The authorised person allowed his assistant to work too close to the cable without wearing adequate PPE (flash suit).

Root cause

The wrong cover plate was removed, exposing the workers to live 11 kV conductors. He counted from the wrong side and used a low voltage multimeter to test the live 11 kV cable.

Contributing factors

- The authorised person had not taken all the risks into account when conducting the risk assessment, nor had he explained the dangers and hazards of the task to his assistant.
- He did not follow the correct safety rules and operating regulations.
- He was not fully concentrating on the job at hand.
- He was late in performing the planned switching operations and was pressurised by other staff waiting for him to finish so that they could work on the cable.
- No flash suit was worn.

Conclusions

In the ensuing investigation, it was found that the authorised person's mind was not on the job, as he had had an argument with his wife before leaving for work that morning and was late in isolating the cable. He was pressurised by staff waiting to work on the cable and did not follow the correct procedure in order to get the work done. He rushed the job and picked up the wrong tester (low voltage multimeter) to test the 11 kV cable. He failed to wear a flash suit and did not make sure that his assistant was safe by allowing him to work too close to the back of the panel without the required PPE.

Remedial action

- All existing circuit breaker panels, in all substations, to be checked to make sure that they are labelled correctly and in the correct manner, in terms of the company's regulations, i.e. panels should be labelled on the front, back and top of the panel and, where possible, on non-removable covers.
- A standard operating procedure (SOP) needed to be compiled, stating the correct safety procedure to remove the back cover and test the cable, before removing the tape.

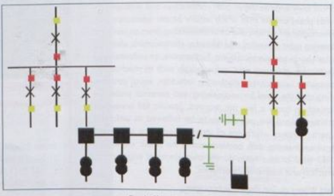

Fig. 1: Electric network.

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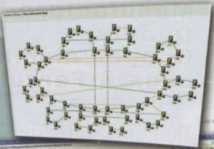

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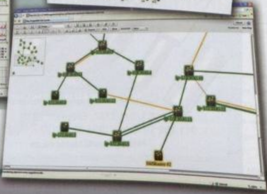
RuggedNMS is fully-featured enterprise grade network management software based on the OpenNMS platform. Specifically for the rugged communications industry, RuggedNMS provides a comprehensive platform for monitoring, configuring, and maintaining mission-critical IP-based communications networks, such as those found in substation automation and "Smart Grids" for electric utilities, intelligent transportation systems, and advanced control and automation for industrial processes.



UNIQUE CONCEPT SOLUTIONS

Most effective means of control	Elimination
	Substitution
	Separation
	Administrative control
Least effective means of control	Personal protective equipment (PPE).
Elimination	Whenever possible, eliminate the hazard. Eliminating the hazard eliminates the risk.
Substitution	When eliminating a hazard is not practical, consider substituting a less hazardous alternative. For example, you might replace a noisy machine with a quieter one.
Separation	Isolate the hazard with mechanisms such as isolation and lock out, machine guards, barricades or interlock.
Administrative control	Develop controls such as safe work procedures and improving operator skills (training).
Personal protective equipment (PPE)	This is the least effective risk control. The use of PPE alone is not adequate and must be supported by one of the controls above.

Table 1: The hierarchy of control.

- Training needed to be provided, on the above SOP to all staff required to remove such covers.
- It was decided that an insulated rod or pole should be held on the front of the panel that would be visible from the rear of the panel, as well as the other identifying method used in this incident.
- It was also decided that, if it were required to test 11 kV conductors in a similar situation before the tape is removed, they shall be tested using a proximity tester.
- The tester should be fixed onto an approved insulating rod of the correct voltage rating, maintaining safety clearance and an approved flash suit shall be worn.
- All conductors are to be discharged using an approved single pole discharge device before attempting to remove the tape, after confirming that they are dead.
- All panels are to be painted different colours to indicate their function i.e. red for a ring and blue for an incomer (this can also assist with identification).
- In order to maintain safety, it is essential that a risk assessment exists for each task.
- A risk assessment (Take 5) must be carried out at all work sites, over and above the general risk assessment as the risk changes at each work site although the task remains the same.
- Risk assessments to be reviewed to ensure that they cover all areas (including the hierachy of control), training to be conducted.
- It is a misconception that PPE is the first line of defence, in fact it is the last!

Therefore, staff are to be trained on Hierachy of Control to ensure safety of personnel.

- All safety rules and operating procedures to be reviewed, updated and monitored regularly.
- Enforce discipline at the work site.
- Ensure compliance with rules and regulations.
- It is essential to comply with the OHSAct and to follow company safety rules and operating procedures. This is not only a legal requirement, but can also prevent damage to equipment, prevent injury to personnel, and save lives.
- Full flash suits must be worn when testing for zero potential and during all MV/HV operations and other staff to stand away, in such a position that they cannot be injured by an explosion.
- Training MV/HV Operating must be conducted and reviewed every two years (refresher courses conducted).

General

You should always consider what can go wrong and what will be the consequences. In this situation, what voltage am I testing and what safety precautions do I need to take?

Always use a reasonable man approach; always ask yourself – would I let my 16-year-old-son or daughter do the job? If the answer is no, then why should I do it, or ask someone else to do it. It must be remembered that for every action there is a reaction.

No operating condition or urgency of service can ever justify endangering the life of anyone. Remember: safety before production, not production before safety! There is no substitute for safety.

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South African power system status overview

by Al'louise van Deventer, Eskom

This paper focuses on the status of the South African power system and electricity consumption. System status is as recorded in October 2014 and is merely a snapshot of the electricity consumption, the generation available and the forecast of the power system until February 2014.

Eskom shed load for the first time in six years for 14 hours on 6 March 2014. This was due to a major coal supply incident in a very tight system, exaggerated by extensive rainfall throughout the country. There were three more load shedding events during June 2014 due to multiple unit trips, as well as a constrained power system in meeting demand. The system continued to remain tight and vulnerable over winter.

Demand reduction through the various demand response products available as well as voluntary requests have been successfully assisting during the winter period to ensure the balance between supply and demand is maintained. There is significant effort by the utility's generation division to improve plant reliability and execute maintenance as planned.

This paper gives an overview of the status of the South African power system as observed in October 2014.

The focus will be on the following elements:

- Demand overview (electricity consumption)
- The contribution of current renewable generation to the generation of the country
- The summer and winter profiles, and the specific challenges associated with each season
- The actual generation dispatch process
- The usage of what is known as emergency reserves
- The system status outlook for the next four months

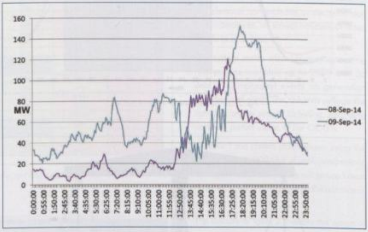

Fig. 1: Wind 5 minute generation profile for 8 and 9 September 2014.

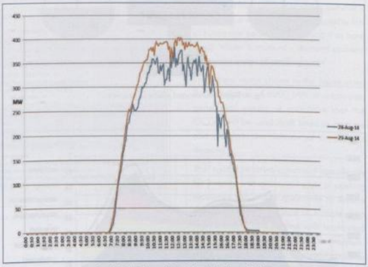

Fig. 2: Solar PV profile for 28 and 29 August 2014.

Demand overview

The peak demand for 2013 was 35 421 MW. The year-to-date (YTD) peak demand for 2014 is 35 677 MW (considering only Eskom generation and firm imports). These numbers include the contracted demand reductions used on the day. When considering the supply from non-Eskom generators (sold to Eskom) the peak demand for 2013 was 36 002 MW, and the YTD peak of 2014 is 36 170 MW.

Current renewable generation contribution

Renewable independent power producers contribute between 500 and 600 MW (note this is not the total installed capacity of renewable generation) to the generation capacity. The wind contribution is about 140 MW and the solar contribution is about 400 MW.

Fig. 1 shows the contribution from wind generation for two days in September 2014. From this profile it can be seen that the contribution from wind is significant over the evening peak period (16h30 to 20h00). A similar profile was observed in the winter period. This is very helpful as winter periods have very high evening peak demand.

The solar PV contribution is up to 400 MW at

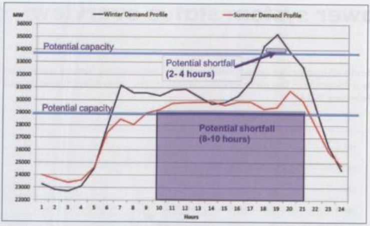

Fig. 3: Summer and winter demand profiles.

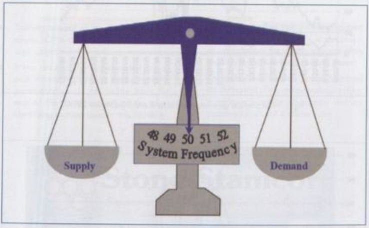

Fig. 4: Supply and demand effects on frequency.

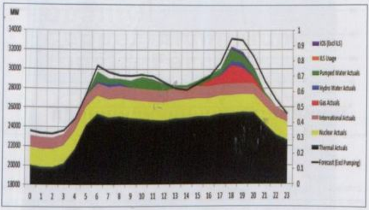

Fig. 5: Actual generation dispatched.

times. In Fig. 2 the solar contribution can be seen for two days in August 2014.

From the profile it can be seen that the typical dome profile of PV solar is significant contribution during the summer months when the demand (electricity consumption) profile is flat (table mountain shape). This implies that the burden on the peaking plant could potentially be reduced due to this.

Summer and winter profile overviews

The summer (November to February) and winter periods (June to August) are characterised by different constraints. Winter is the period when the highest demand is experienced in the country. In Fig. 3 the winter and summer demands are illustrated.

Meeting demand in winter

If generation in winter was to be reduced due to tehcnical issues, the potentail capacity as illustrated in Fig. 3 is what would be available to meet demand. As can be seen from the graph, there is a shortfall (insufficient generation). In the winter period the highest demand is experienced in the evening between 17h00 and 21h00. The constraint is for a two to four hour period as illustrated. The use of peaking plant, specifically the expensive open cycle gas turbines to meet the shortfall is for a two to four hour period. Note that the open cycle gas turbines are considered peaking plant and part of the emergency reserve category. This means they are used as a last resort when all other sources have been used.

Meeting demand in summer

The summer demand is significantly lower than the winter demand, so most maintenance on generation plant is performed in this period when. Even though demand is lower, it is more challenging to meet demand during this period than winter. The nature of the demand profile is flat (table mountain shape) which relies heavily on peaking plant resources in the event of a constraint. From Fig. 4 it can be seen that if there is a generation capacity constraint, the shortfall generally is for up to ten hours or more. This means if not enough base load plant is available, the peaking plant including the open cycle gas turbines usage is high and very extensive.

Actual generation dispatch process

Maintaining this balance ensures that the frequency remains within 49,8 and 50,15 Hz.

How Eskom meets demand

The process starts with the forecasting of demand (including the operating reserves) needed. Operating reserves is necessary to cater for deviations on demand or supply and operating reserves. The hourly average generation schedule to meet demand is determined. If there is insufficient capacity to meet demand the emergency reserves will be scheduled as needed. Note that the open

System Status Including Operating Reserves		6000 MW Unplanned Allowance			
Week Starting	Peak Forecast	Expected Available Capacity	Expected Capacity Shortfall Incl OCGTs	Expected Capacity Shortfall Incl 1000MW OCGTs	Expected Capacity Shortfall Excl OCGTs
06/Oct/2014	31083	33499	162	-947	2247
13/Oct/2014	31060	34023	-65	-1174	2434
20/Oct/2014	30939	33337	-114	-1019	2319
27/Oct/2014	30798	32882	84	-878	2178
03/Nov/2014	30764	32392	-663	-1625	2525
10/Nov/2014	30896	32576	-547	-1452	2752
17/Nov/2014	31067	32633	-1227	2136	-3636
24/Nov/2014	30787	32184	-1003	-1965	3265
01/Dec/2014	30276	32451	-761	-1723	-3023
08/Dec/2014	30563	32265	-873	-1982	3282
15/Dec/2014	29364	32260	-785	-1894	3194
22/Dec/2014	27934	29568	-366	-1475	2775
29/Dec/2014	27800	31376	-562	-1671	2971
05/Jan/2015	30101	32285	-12	-1121	2421
12/Jan/2015	30591	33518	287	-822	2122
19/Jan/2015	30605	33518	338	-771	2071
26/Jan/2015	30983	33295	-85	-1047	2347
02/Feb/2015	31073	33517	-15	-977	2277
09/Feb/2015	32020	33677	-481	-1443	2743
16/Feb/2015	31979	33677	-302	-1264	2564
23/Feb/2015	32266	34346	-589	-1551	2851
02/Mar/2015	32148	34493	198	-764	2064
09/Mar/2015	32226	34493	115	-842	2142
16/Mar/2015	32248	34459	-297	-1258	2558
23/Mar/2015	31981	33670	-311	-1420	2720

Table 1: System status for the next four months.

Color	Shortfall excl. OCGT's	Implications for use of resources during the week
GREEN	Adequate capacity to meet demand and operating reserves	Normal generation required
YELLOW	Shortfall of up to 1000 MW	Sufficient operating reserves Some OCGTs may be required but not extensively. Water utilization not an issue ILS only required to respond to low frequencies
ORANGE	Shortfall of 1000 – 2000 MW.	Operating reserves will be met with limited emergency resources Combination of water and OCGT's will be used to meet demand (neither used to full capacity on a given day) ILS only required to respond to low frequencies
RED	Shortfall of 2000 – 3000 MW (3 days)	Some operating reserves but not full 2000MW Combination of water and OCGT's will be used to meet demand. Low risk of reaching minimum gen hours at hydro stations ILS only required to respond to low frequencies
PURPLE	Shortfall of 3000 – 4000 MW (3 day3)	Very limited operating reserves. All OCGTs required most of the day throughout the week and will be utilized over the weekend to replenish dam levels Water utilized extensively during the day, risk that by Thursday or Friday minimum gen hours will be reached ILS will be required on Thursday to meet evening peak
BROWN	Shortfall of more than 4000 MW. (2 days	No operating reserves, short on demand All available resources required (incl OCGTs, GT's) required most of the day throughout the week and will be utilized over the weekend to replenish dam levels. Water used extensively and minimum gen hours will be reached before the end of the week. ILS will be required during peak periods, high risk that their contract time will be reached.

Table 2: Usage of resources for a particular colour.

cycle gas turbines are considered emergency reserves.

In Fig. 5, a particular day of dispatched generation resources is illustrated. Note that the international actual is the 1500 MW import from the HVDC lines from Cahorra Bassa (Mozambique). The red part illustrates the open cycle gas turbine usage. The dispatch process has a specific merit order that is followed.

If all resources, as per the merit order, have been dispatched and there is still insufficient capacity to meet the demand a forced demand reduction (load reduction or load shedding) will be implemented. The purple strip indicates the incentivised demand reduction (DMP) that was used on that day.

The graph only indicates plant that is dispatchable. The IPPs, including the renewable plants, must run and are not shown here, because at present this plant is not dispatchable.

System outlook for the next four months (as at 8 October 2014)

The system outlook is merely an indication of what can be expected on the power system and how constrained the system is likely to be. This can change regularly depending on the generation capacity available or changes on the demand. The generation capacity gets influenced by planned and unplanned events. The demand can increase or decrease due to temperatures, or school holidays or other events (e.g. strikes).

The system status also assumes operating reserves are available up to 2000 MW (to deal with unplanned events on generation and demand side). The columns reflects the tightness of the system including, excluding and with partial usage of the OCGTs.

In Table 1 the system status shown using the assumption of 6000 MW of unplanned events, is indicative that the OCGTs will be used most times to manage and maintain the balance of supply and demand.

The colours in Table 2 indicate the usage of peaking plant resources and is reflective of how constrained the power system is. There is a slight difference from the usage of resources perspective from summer to winter. Summer is more of an energy problem which places lots of burden on peaking plant (using it as base load). Winter is more of a demand problem with lesser usage of peaking plant.

The system status shown in the figure using the assumption of 6000 MW of unplanned generation events, is indicative that the OCGTs will be used most times to manage and maintain the balance of supply and demand.

The system remains constraint specifically for summer with extensive usage of peaking resources. All efforts are made to ensure the generation capacity is sufficient to meet demand and to deal with unplanned (contingencies) events on the power system. Customers are strongly encouraged to reduce demand especially for non essential loads such as air-conditioning, the use of pool pumps, etc. The system is dynamic and the system status overview is merely a snapshot of the system at a particular point in time.

Acknowledgment

The graphs are mostly compiled by Hendri Bower, an engineer at Eskom.

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Design criteria implementation for the Network Development Plan: Hursthill substation

by Riaan Swanepoel, City Power

The City of Johannesburg is embarking on a new spatial vision for the city in line with its growth and development strategy 2040, based on corridor orientated development. This approach envisages that growth of the future city will be guided by well-planned transport corridors allowing for high densified mixed residential developments in close proximity to affordable transport nodes. The high residential developments must be supported by commercial and retail developments to support work and leisure opportunities.

The legacy spacial planning left the city with sprawling low density areas without a viable public transport system. The majority of poor and working class citizens still live on the fringes of the city, resulting in long distances to travel to work at a high expense. The National Household Travel (2003) study conducted by Stats SA found that the average travel time for commuters making use of public transport is 59 minutes. This excludes the time to walk to the designated pick-up or dropped off points. For a Johannesburg resident staying in an area like Diepsloot or Orange Farm, it means waking up before dawn to ensure getting to work on time in the CBD or northern suburbs.

One of the proposed corridors is the Empire Perth Corridor. The proposed corridor will create a link between Soweto and the Northern Business areas like Rosebank and Parktown. The role of City Power will be to create a favourable environment along the corridor by ensuring adequate capacity exists for the development of high density residential and commercial zones along the Corridor of Freedom COF. Within the current focus area affected by the COF, the population count is 25 242. With the creation of the corridor the expected future population count for the focus area will be 155 245.

Hursthill area

The proposed developments cover various substation zones within the City Power supply area. A key focus area within the Hursthill substation area will be used to discuss the change in planning philosophy to accommodate the increase in demand in a small area.

Hursthill substation area is 99 km^2. It is a fully build up area with 42 604 residential customers and 941 large power users. The areas have limited commercial developments, and include areas like Auckland Park where key customers like SABC, University of Johannesburg, Helen Joseph and Milpark hospitals are housed.

The area is fully utilised and an increase in the demand at the substation is mainly due to the natural growth of the existing customers and not new developments to date.

Planning methodology

The existing City Power electricity grid system is a mixture of various methodologies being used by different municipalities. It does mean that different methodologies do exist throughout the network and cognisance must be taken when future network development plans are implemented.

The Hursthill substation falls within the central grid of City Power. Capacity is purchased from Eskom at 275 kV at Fordsburg substation. The capacity is stepped down to a voltage of 88 kV. The capacity is transferred to Orlando switching station, from where radial feeds provide capacity to the relevant substations. The transmission grid always operates at N-1 condition to ensure the load to any substation will not exceed the current carry capacity of one overhead line. Each substation also has an independent standby transformer able to carry the capacity of any 11 kV feeder board at the station in case of an outage/loss of a transformer. Hursthill substation is equipped with 3 x 45 MVA 88/11 kV transformers. The existing demand at the substation is approximately 80 MVA. The substation has been identified in the Transmission Masterplan for the installation of an additional power transformer and 11 kV feeder board at a later stage. With the initiative to establish the Corridors of Freedom, the planned upgrade will have to be brought forward and an additional substation will be required.

All the proposed developments in the Hursthill area will be in close proximity to the existing substation. The network development plan for the area must consider methods to develop the electrical infrastructure in the area. A section of the proposed development will form the basis of the distribution planning methodology that will be used in the area. For ease of reference, it will be called Area A.

Determining the diversified demand usage in focus area A

The focus area is located Northwest of the Hursthill Substation. It is directly adjacent to the Bus Rapid Transit route making it an ideal area for the densification and redevelopment of residential units. At the present moment, the area is zoned as residential one units

Fig. 1: Hursthill substation coverage area.

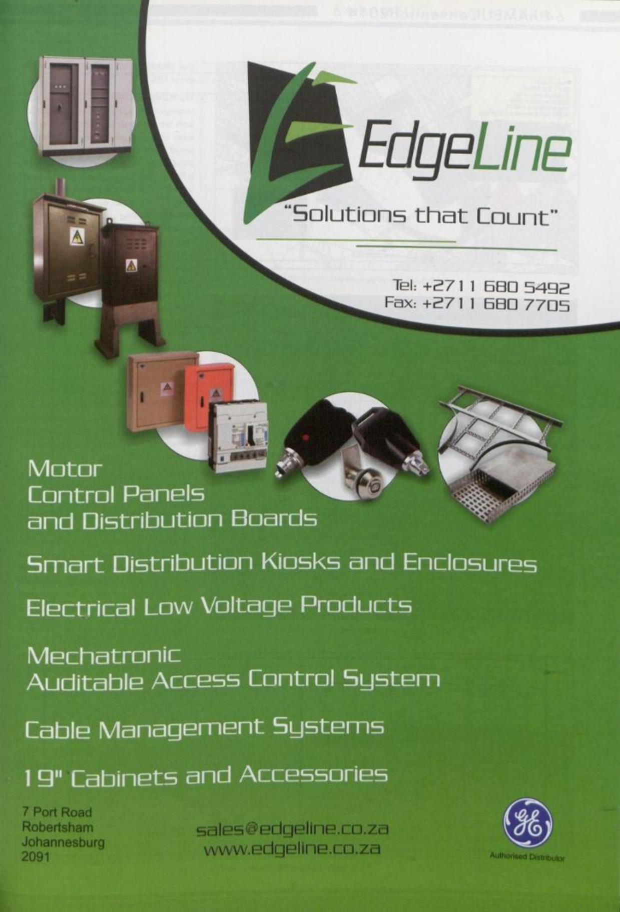
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Fig. 2: Subdivision of area into erfs.

Load reference	Density target (DPH)	Future dwellings	Future population	MVA @ 3,5 kVA/unit
21	100	204,59	724,77	0,72
22	120	334,95	1076,84	1,17
23	80	70,79	257,37	0,25
24	80	147,79	530,37	0,52
25	100	180,96	638,88	0,63
26	80	364,03	1302,08	1,27
27	80	265,94	971,81	0,93
53	130	337,43	1099,28	1,18
54	80	340,62	1246,85	1,19
55	100	83,59	286,78	0,29
56	220	133,31	399,94	0,47
57	220	378,37	1135,12	1,32
58	220	191,18	573,55	0,67
59	220	328,72	986,17	1,15
74	100	379,23	1296,68	1,33
81	150	91,10	300,29	0,32
82	150	104,79	353,36	0,37
83	180	95,14	303,43	0,33
84	180	981,11	3240,33	3,43
85	150	412,27	1380,80	1,44
97	150	190,86	662,58	0,67
Total		5617	18 767	20

Table 1: Plan of area redevelopment.

and utilisation coverage of the houses is about 70%.

The ADMD from the latest load centre/MSS readings indicates that individual residential units are using between 5 and 6 kVA at the local load centre/MSS. The units are all zoned as "Residential 1" and the typical stand size is in the region of 250 m² with a FAR of 70%. The proposed developments are all to be zoned as Residential 3 and 4 areas, with target densities between 80 and 220 dwelling units per hectare. This results in a tenfold increase for the housing requirements within the existing developed area which will result in smaller apartments with less energy requirements. The typical ADMD load profiles for low to middle income groups living in medium to high rise buildings is between 2,1 and 2,85 ADMD. The design allows for an ADMD of 3,5 kVA at MV distributor level, allowing for 23% growth per load allocation.

A key factor to consider is the limited space on the sidewalks, along the main BRT corridors the sidewalks are limited to about 1 m, while on secondary roads it is roughly between 1 and 2 m. The sidewalks contain all other services (water, Telkom, fibre and sewer) and the ability to install new cables is limited.

The existing distribution network in the area is also more than 40 years old. Part of the new design must consider the possible replacement of the existing networks. These proposed developments will all be driven by private development. This will result in sporadic development within the defined area and exactly what each development will consist of is not known. For the design City Power will use the maximum rezoned density that the city will allow in the RSDF and develop a network that can accommodate 100% re-development of the area.

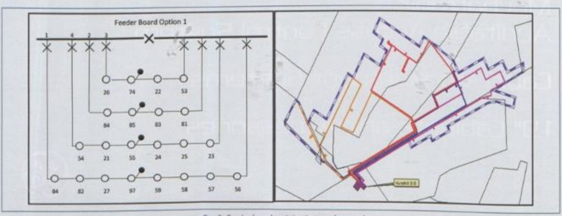

Fig. 3: Feeder board and distribution of option 1.

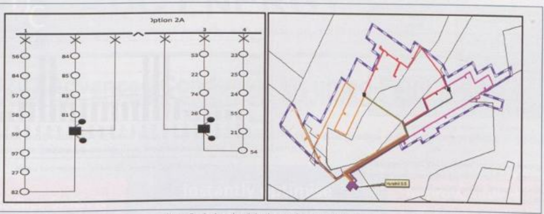

Fig. 4: Feeder board and distribution of power in option 2.

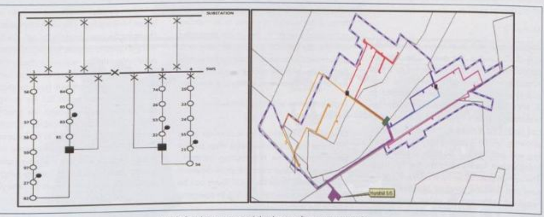

Fig. 5: Switching station and distribution of power in option 3.

Distribution networks (capital cost considerations)

Method 1

The conventional distribution network for City Power can be summarised as follows. The majority of City Power's distribution network operates at 11 kV. For main or radial ring systems, City Power uses 185 mm² x three-core copper or 300 mm² x three-core aluminium cables. The designed capacity City Power uses per cable is 6 MVA. Cables are normally loaded to 5 MVA allowing about 15% for natural growth.

At a substation a 11 kV feeder board consist of 2 x 2500 A incomers, 1 x 2500 A bus section and 14 x 800/630 A distribution feeders. Two 45 MVA transformers are connected to a feeder board, one to provide the capacity, while the other floats and will be connected with an automated chop-over scheme if the feeder transformer trips. Seven feeders are connected on one side of the bus section and return via the area to the same feeder board. Loading each of the rings to a maximum of 6 MVA results in a maximum demand of 42 MVA per feeder board with full N-1 contingency. The scheme is very reliable and the utilisation factor of the cables and breakers is 50%.

Four ring feeders will be required to reticulate the focus area. Each ring feeder design will allow for a maximum connected demand of 5 MVA allowing spare capacity for future

							Capital cost summary of focus area A			
Design option	Number of distributors @ S/S	Total length of 300 mm Cu	Total length of MV cable 300 Alu	Usage factor dist	Number of dist's for COF in HH S/S area	Additional feeder boards req.	Focus area cable requirement @ R1000/m	Substation 11 kV breaker cost @ R270k/CB	SWS breaker @ R 270 k/CB	Subtotal
1	8	0	13 535	50%	26	2	R13 535 000	R2 160 000	R0,00	R15 695 000
2	6	0	10 827	67%	18	1,5	R10 827 000	R1 620 000	R0,00	R12 447 000
3	4	2892	7614	67%	12	1,5	R11 084 400	R1 080 000	R2 700 000	R14 864 400

Table 2: Design comparison

Option	% Increase from lowest
Option 1	–
Option 2	186%
Option 3	120%
Option 2 with two open point design	108%

Table 3: Network losses experienced during peak loading.

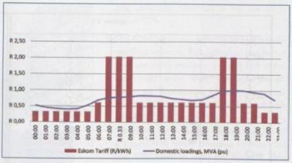

Fig. 6: TOU tariff (high demand season) vs. domestic load profile.

growth. The total length of MV cable required will be 13,5 km utilising eight switches at the feeder board. Using this scheme within the Hursthill Substation area will result in a total cable requirement of 65 km and 26 new 11 kV feeders breakers (two x feeder boards) at the substation. This will become impractical at both the substation and sidewalks to install all additional services.

Method 2

Another approach is to use a pure standby distributor within the area. The standby distributor has no load connected to it and is connected to two radial distributors. Each radial distributor can now be loaded to 5 MVA as the standby will provide full feedback capacity in case of a first port of call fault. This is done by a three-leg design, allowing full N-1 contingency but the third leg will not have a backup supply if an independent fault occurs on the third leg. This option does allow for a saving in capital cost and limit the amount of infrastructure required. Although six cable circuits are required, it still proves a problem with the total amount of switches required and available sidewalk space along the BRT route for the cables to be installed. The control point will be at a suitable end point of the distributors. A key disadvantage to consider is the number of customers affected when a first port outage occurs on a distributor as shown in Table 2. In option 1 about 40% fewer customers will be affected on a distributor outage than in option 2. The affects can be mitigated by moving the open points into the distributors, changing the system from a single point operating system to a two/dual point operating design.

Another approach (option 3) is to create a switching station within the focus area. It will allow for the least amount of 11 kV feeders required at the substation which is imperative for the specific application. The feeder cables to the switching station can all operate in parallel, allowing a feeder cable, from the substation to the switching station, to trip without affecting the customers downstream. Installing four x 300 mm three-core copper XLPE cables will ensure a firm capacity of 27 MVA. With four distributors loaded at 6 MVA, the switching station will still be within firm capacity limits.

From a pure capital point, option 1 is the most expensive option. It requires the most amount of cable and switches at a substation. With the standard substation design that City Power implement, the limit of available switches per substation will be exceeded. A big limiting factor is the number of cables to be installed in the road reserve. All the utilities associated with the city will have to upgrade services to accommodate the proposed amount of people that will reside in the area, thus space on the limited road reserve area will be at a premium.

Technical losses within the distribution networks

One of the biggest factors to consider is the I^2R losses that are experienced when current flows through the distribution network. By designing the network into different configurations, these technical losses can be reduced which means a saving in operating cost to the service provider.

Considering the SCADA data in the area and taking a load profile of these typical residential feeders, it can be seen that the highest demand is experienced between 07h00 and 10h00 and then again between 18h00 and 20h00. Eskom also charges City Power on a time of use tariff scheme, resulting in the highest charges being enforced during these peak periods.

Assuming, that the load will be constant over an hour period and that the resistive component of a cable is constant, we can consider what the typical I^2R loss over a designed network will be. This value will change on a daily basis as the demand usage of an area is consumer usage dependant and that open points in the networks can change. For the comparison, the network will be assumed to be unchanged over a 24 hour period and the maximum future demand envisaged for the area over the respective distributors will be used.

With option 1, the cable installed in the ground is about 25% more than the cable used in option 2 or option 3. This is because eight feeders are installed compared to the six in the other options. The distributors are, however, less loaded which will influence the I^2R losses the cable network will experience. Option 2 requires less cable and the total cable network resistance will be lower, but the current component, which is the main factor, is higher as each distributor operates at a higher MVA loading. This can be mitigated by changing the open points in the network from a single operational point to a two operational point system similar, as shown in the switching station design. This will require longer outage periods as operators will have to change two possible open points but the saving in operational costs validates the practice. Option 3 uses minimal cables to transfer capacity from the substation to the focus area. These feeder cables are permanently under a high load as they are the main capacity transfer network. The rings from the switching station will have fewer losses as these rings are relatively short.

Conclusion

It can be seen that option 2 is the most cost effective option for a new installation. The design will require long distributors from the substation and it does carry a risk of a large number of customers being affected if cables are damaged close to the substation. Option 1 will operate with the least amount of technical losses on a continuous basis, but it does require a high capital cost to install and may not always be feasible to accommodate at the substation level.

With the practical limitation of road reserve space, option 3 is seen to be the best solution. With a cable spacing of 200 mm, the four circuits will comfortably fit within the relatively small road reserves. It also allows operators to trace and restore cable faults on short ring systems, cutting down on restoration time. All faults can also be operated locally at the switching station and will prevent complete feeder board trips if the feeder breaker fails to operate, thus no large loss of supply from a complete feeder board takes place.

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Applying an asset health solution for transmission and distribution networks

by Steven Hagner and Hennie Nel, ABB Ventyx

Data-driven predictive maintenance and asset replacement strategies have been a dream for electricity transmission and distribution (T & D) companies for decades. Now a number of factors have come together to make that dream reality with the help of an asset health solution.

On one hand, the requirement for such solutions has reached a point that T & D companies have seen that they can no longer continue business as usual. Well over half of these companies are seeing their operations and maintenance budgets remain flat or even fall, despite regular increases in the costs of parts and labor. That might be manageable if the assets being maintained were all still quite new, but even for critical assets like large transformers the average age is approaching or already beyond the design lifetime.

Where previously asset replacements justified themselves via a higher rate-base, now more and more regulators are shifting to efficiency-based rate setting. In other words, the demand is higher than ever to get as much life out of those old assets as possible. And finally, to top it off, the experts who have been maintaining these assets for the last 30 to 40 years are just a few years away from a well-earned retirement. Indeed, utilities must change to adapt to these changing requirements.

On the other hand, advances in technology are providing the opportunity to use resources more effectively, to capture the knowledge of those experts before they retire, and to help T & D organisations optimise and prioritise their maintenance and replacement strategies like never before. Modern information technology (IT) software solutions are using the masses of data available from operational technology (OT) in an IT/OT convergence that is showing significant performance improvements, increased reliability of systems, and reduced operational/maintenance costs.

Today at organisations trying to maintain numerous and varied assets across one or multiple sites, information from disparate sources, including time and usage-based inspection data, needs to be manually reviewed and assessed by human experts to identify trends and evaluate risks. Critical maintenance and replacement decisions are based on the interpretation of this data, but this process is far from perfect. It is inefficient and open to human error, and is also proving increasingly difficult for the power industry as key experts retire from the business.

An asset health solution allows utilities to perform true predictive monitoring and maintenance of critical assets for immediate and long-term efficiency improvements. It accesses information from SCADA systems and other online and offline data sources, and combines this with trends based on industry performance models established from decades of experience.

For Ventyx, this historical data is based on ABB's deep expertise in building, servicing and refurbishing electrical assets, but critically also leverages the experts at utilities who are eager to help their companies capture and formalise their knowledge for future generations.

The intelligence the asset health solution assembles about equipment is used to predictably alert engineers to assets that are at risk of failure. It presents information on dashboards in a variety of formats to enable better decision making and provides proactive messages with required corrective actions and the timeframe in which they need to be completed to avoid failures.

Beyond that it helps organisations prioritise both their maintenance and replacement to help them get the most reduction in the risk of failure using the restricted funds they have available.

Large and small network operators are now looking at how they can leverage an asset health solution to enable data-driven predictive maintenance and to optimise their use of existing assets. American Electric Power (AEP) is the largest transmission company in the United States and is already benefiting from the implementation of such a solution.

Asset health

Effective management of the health of assets requires real-time and historical data from a variety of IT and OT sources. To turn this data into information, however, software algorithms are needed to analyse, evaluate and feed back required actions to operators and maintenance teams. Such algorithms are centered on in-depth understanding of the power industry and present information based on a balanced view of operational performance, financial performance and risk to the business, highlighting opportunities for improvement and optimisation across assets' lifecycles.

The modern asset health solution pulls detailed real-time and near real-time data from all assets along with other offline data from disparate data sources, to ensure a complete picture is obtained and efficiency can be optimised. It aggregates information from online and offline data sources, such as costs, manufacturers' data and industry standards. It then prioritises assets that need attention and can send this data to enterprise solutions such as work management and maintenance management systems. As well as providing all data required to enable the strategic use of resources, this approach gives the added benefit of having all information in one, central location.

When planning the implementation of an asset health solution, questions need to be asked about what data should be gathered, whether the quality of the data is sufficient to base vital business decisions on and, for it to be effective, how to implement a single solution to cover critical assets. The solution needs to address all of these issues, pulling from both IT and OT expertise.

Algorithms can monitor over 100 discrete parameters for each class of asset, bringing together previously disparate data such as historical corrective maintenance and near real-time feeds of existing conditions. To ensure data quality is sufficient, it should be continually assessed through the use of smart filters, which look at the consistency, validity and completeness of data while also checking for duplicate data.

To cover critical assets, the solution also needs to be equipment- and sensor-agnostic. Even older equipment, with limited numbers of sensors, can benefit from being included within an asset health solution as many of the data points are not near real-time. Obviously areas such as dissolved gas analysis (DGA) for a transformer would suffer from not having a real-time feed, but many other areas would still provide clear indicators as to asset health and help to streamline the maintenance required and reduce failure risks.

As the asset health solution monitors multiple asset types with a primary focus on risk of failure, information needs to be displayed to operators in a clear and consistent form so they can quickly identify any areas of concern and rapidly navigate to detailed information about an individual asset when a risk is flagged. The system should help a facility gain a significantly more detailed understanding of problems and failure modes of an asset to allow them to implement effective asset management programs that help prevent unexpected failures. Potential failures should also be objectively assessed for risk and criticality, and managed with a proactive alert system to ensure relevant personnel are advised in good time to prevent any catastrophic failures.

Data which is distributed across locations in different formats can be brought together to give a complete picture of the business and to guide strategy for optimising operations. Armed with information from an asset health solution, maintenance and inspection routines can be optimised using predictive rather than time-based information. This can significantly reduce maintenance costs, and the additional information the system provides can help to improve workforce effectiveness and decision making processes.

Customer study

American Electric Power (AEP) operates a 64 000 km network, the largest electricity transmission system in the United States, serving more than 5-million customers across eleven states. With one-third of their transformers older than 50 years, and another 18% older than 60 years, the need to streamline asset renewal while maintaining excellent service had become of paramount importance. AEP committed to ensuring the reliability of their transmission infrastructure, properly prioritising maintenance, and addressing the replacement of their aging assets. To achieve these goals, AEP set out to create a robust asset health solution.

With experience in designing and implementing systems that balance information technologies and operational technologies, ABB Ventyx was brought on board to develop this highly strategic and forward-thinking platform. With the surge of unprecedented data collection by smarter sensors in the field, ABB Ventyx was capable of merging this practical and actionable data to create a system that integrated all technologies. In addition, according to Jeff Fleeman, Director of Advanced Transmission Studies and Technologies at AEP, "The collaboration on this topic brings together globally acknowledged experts in power equipment and business intelligence, with AEP's scale, size and technology experience as an owner operator of transmission infrastructure."

The Asset Health Center solution automates data collection; applies advanced analytics to real-time, transactional, and historical data to suggest asset management decisions; and advances the effectiveness of assets through comprehensive business intelligence.

Summary

The dream of doing maintenance only when it is really required and replacing assets just before they fail is becoming possible. An asset health solution like the one offered by ABB Ventyx enables T & D companies to consolidate the rapidly growing volumes of data about their assets. They can benefit from industry-leading algorithms which identify assets with a high risk of failure, and generate predictive messages suggesting to O&M personnel the type, timing and even safety conditions for required maintenance. They can leverage maintenance prioritisation and optimisation algorithms to guide them in their work, while incorporating the knowledge that their own experts have gained over 40 years of maintaining these assets.

An asset health solution, along with the internal change management to leverage that solution, is the key to making predictive maintenance and asset replacement a reality.

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City Power Johannesburg: Response to potential load shedding

by Stuart Webb, City Power

This paper will provide a brief history of City Power, the electricity utility which distributes power to consumers within the City of Johannesburg's licenced area of supply, and will describe the various options available to mitigate the impact of future load shedding should this be necessary to maintain the stability of the national grid.

For any electrical grid to remain stable the available generation capacity must match the load demand of the consumers, in simple terms supply must match demand. At any one time the generation capacity of a system will generally be less than the installed capacity as certain plant will be out of service as a result of planned or forced outages. The difference between the national maximum demand and the available generating capacity is referred to as the reserve margin and in an ideal world this should be around 15%.

If the system demand at any instant in time is greater than the available generation the system will become unstable, and extensive and progressive blackouts may result. This would be catastrophic for the country and must be avoided even if drastic measures are necessary. If the demand cannot be quickly reduced to match generation, large blocks of load must be intentionally disconnected.

In 2008 the national generation levels could not meet demand during peak periods due to unplanned unavailability of plant and the country experienced a series of forced outages which quickly became known as load shedding. These forced outages resulted in extreme inconvenience to the public and adversely affected companies, businesses and the national economy. This was a new phenomenon for which the country was ill-prepared.

A brief history of City Power

When the now defunct Metro Electricity was formed, which was the City of Johannesburg's electricity service provider, it amalgamated several former municipal electricity undertakings into one new utility. It brought together five essentially independent systems, namely Johannesburg, Randburg, Roodepoort, Sandton, and Johannesburg South.

There were also a few minor networks included such as Alexandra, Dainfern, Lenasia and Brink's Vlakfontein.

In 2001 Metro Electricity was rebranded as a new company and called City Power Johannesburg. More recently the Modderfontein and Midrand areas have been added to the supply area.

The technical designs of the former municipal areas are diverse in terms of plant and equipment, voltages and operating philosophies. These technical differences made interconnection of the various networks of little benefit and the systems are essentially operated independently.

Fig. 1: Ripple control coupling cell.

City Power purchases the majority of its energy from the national generator, Eskom, for onward distribution to its customers. In addition, a small amount of power is supplied from the independently owned and operated Kelvin Power station.

City Power's customer base is in excess of 360 000 and the maximum demand around 2600 MW.

The challenges

As alluded to above, City Power procures the vast majority of its power from Eskom and an alternative source of such magnitude is not available. Over the years countrywide load growth and development has resulted in Eskom's reserve margin falling below the internationally accepted level of around 15% due to various factors not always within its control.

In addition, Eskom's build program has experienced several delays and a significant reduction in grid capacity pressure is only expected to be realised in two to three years.

As a result the possibility of having to quickly reduce system demand during peak periods or following a major system event is ever present. Although a concerted effort has been made by all parties to inform the public of the precarious situation and the response from consumers has been positive, the threat of load shedding still remains.

The impact of load shedding has a significant negative impact on the economy of the region and, indeed, on the country, as well as adversely affecting the lives of the citizens.

Curtailment stages

In terms of NRS 048 – 9 various stages of load shedding are described:

- Stage 1 is defined as a 5% reduction in winter maximum demand.
- Stage 2 is defined as a 10% reduction in winter maximum demand.
- Stage 3 is defined as a 20% reduction in winter maximum demand.

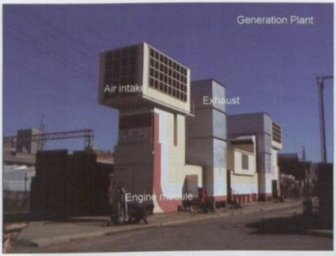

Fig. 2: Cottesloe 40 MW gas turbine installation.

Fig. 3: Kelvin "B" Power Station.

Fig. 4: Typical solar geyser installation.

In City Power's case these stages would equate to around 130 MW, 260 MW and 520 MW respectively.

The duration of load shedding can vary greatly from a few hours up to 8 hours or even longer in extreme cases.

Opportunities

The City of Johannesburg and City Power have recognised the negative impact of load shedding on the economy and the citizens of the city. As a result the city has made a commitment to avoid a repeat of 2008.

Several mitigating opportunities to avoid emergency load reduction have been identified by City Power and have been or will be introduced. The various initiatives available will be described and discussed in the following sections.

Key customer demand response

City Power has a number of high consumption key customers whose annual usage exceeds 5 GWh. The activities of these companies differ widely but all have a potential ability to reduce or shift load without necessarily halting or adversely affecting their production of operation. These companies are fully aware of the impact of complete load shedding on their businesses as a result of the prevailing conditions and are willing to assist City Power to mitigate this situation.

Presently City Power has identified around 112 key customers who have confirmed their willingness to voluntarily participate in a demand response scheme. The proposed, but as yet unconfirmed, repayment incentive rate is R1,11 per kWh and certain criteria will apply for the companies to participate.

It is estimated the potential load curtailment to be gained from this initiative will be around 80 MW.

Geyser control

City Power has installed, over several years, an extensive network of geyser control infrastructure utilising ripple control technology. This form of demand side management is normally aimed at reducing the city's maximum demand during the morning and evening peak periods when energy purchase costs are at their highest. Geyser control can, in addition, be called upon to reduce demand when system capacity is tight or in an emergency situation.

The existing coverage is limited to around 60% of domestic premises although further expansions are planned. The present capacity of the ripple control system allows for an

Fig. 5: Typical photovoltaic installation.

Fig. 6: Domestic smart meter.

immediate reduction in demand of between 50 to 80 MW depending on the time of day and the season.

Gas turbines

City Power has three gas turbine installations situated around the JHB CBD. The capacity of these units is 40 MW each or 120 MW in total. The units had not been used for several years and had been mothballed. Following the 2008 load shedding experience two new refurbished engines were sourced and installed. The units were then operated, but it was found the control circuits were unstable and unsuitable for reliable operation.

It is an option going forward to modernise the control systems allowing City Power to run these units to off-set demand curtailment requests at times of system constraints.

Kelvin Power

City Power has a 20 year PPA (Power Purchase Agreement) with Kelvin Power which commenced in 2001. Kelvin has a reduced capacity availability of around 300 MW following the recent decommissioning of the obsolete "A" Station. The unit price of Kelvin is higher than the Eskom Megaflex tariff and presently Eskom has contracted to purchase all output at the higher rate.

However, City Power has an opportunity to utilise Kelvin's full available output as a contribution to its load shedding quota, although this clearly has financial implications.

Solar geysers

A roll-out of solar water geysers was initiated in late 2012 and the first phase involved the installation of some 60 000 units in various areas. It is the intention in the current financial year to continue with the installation of a further 10 000 units.

It is estimated these installations equate to an evening peak demand reduction of around

7 MW and avoids a future potential load of 45 MW from conventional electric geysers.

Photovoltaic generation

Presently City Power has received a significant number of applications to connect PV to its grid. Eskom funded projects which amount to some 4 MW alone, with further privately sponsored projects in the pipeline. Fully regulated PV programs could yield tens of megawatts of power. Approval for grid connected PV and surplus power buy-back tariffs is awaited from NERSA. In addition a number of larger companies have installed generation plant and they could also be contracted to operate their plant at times of system constraints.

The repayment rate and applicable conditions are presently being developed for submission to NERSA.

Smart metering

A strategic decision to introduce smart metering has been taken by City Power. Both credit and prepaid options are available to customers. Generally, consumers presently consuming <1000 kWh per month will be offered a prepaid meter. In addition to automatic reading functionality the meters have a capability for communication and to switch domestic appliances such as geysers and pool pumps off. It is the intention to fully utilise this functionality to control residential demand where necessary.

Residential time of use (TOU) tariff

A residential TOU tariff is now available to City Power customers. The previously installed, older technology meters were not capable of metering TOU consumption. With the roll-out of smart meters the introduction of TOU tariffs is now supported. The intention is to incentivise residential customers, through tariff signals, to reduce consumption during peak periods.

It is also possible to control the actual consumption during periods of constraint by remotely setting a load limit which, if exceeded, would result in disconnection.

Summary

Currently several options to mitigate the possibility of load shedding are available to City Power, albeit at significant costs. With the options available City Power can accommodate up to a Stage 2 request, but any appeal beyond this cannot be complied with without the deliberately disconnection of customers.

City Power will continue expanding its geyser control systems to all areas – load can be quickly reduced and held off until constraints ease up. The roll-out of smart meters will proceed and the use of these meters to control network loading will also be implemented.

New renewable and energy efficient technologies are being investigated, such as PV power and energy efficient streetlighting. The City of Johannesburg, in conjunction with City Power, has initiated a project to generate electricity from the gas produced at two landfill sites.

The Demand Response initiative will be expanded. It is confidently expected that these measures will significantly contribute to the national effort to reduce system demand and thereby minimise the need for the re-introduction of load shedding.

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Performance target setting and prioritising electrical power system-level investment

by Louis Pieterse, City Power

City Power's engineering operations performance targets have traditionally been informed through benchmarking with overseas utilities, but this approach to target setting has proven to be inadequate. An alternative approach was therefore considered whereby the performance targets are based on the operationally achievable performance levels of the network, subject to the existing characteristics of the infrastructure and its operations.

Due to a lack of system-specific performance models and approaches, international (and national) benchmark studies are most often applied in decision-making to inform expected performance levels (and therefore performance targets). Benchmarking outcomes should, however, be applied with caution, as there are some detailed factors that must be considered for comparative decision-making. A fundamental flaw with a benchmarking-based approach is that, generally, benchmarking ignores current network topology and its influence on the inherent performance level capability of the particular distribution system in question [1].

City Power's network topology, customer numbers and distribution on the network, operating environment and other network topology related variables are very different from that of overseas utilities, and hence the "generalised" benchmarking-based approach to target setting has proved to be inadequate for City Power's purposes (as well as other South African utilities such as Eskom [1]). This finding is most probably true for any individual electrical power utility in the world, for there are no "identical" or "representative" networks internationally – only specific networks constructed subject to specific network topology requirements at specific points in time. City Power's engineering operations division therefore initiated a study into the designed performance level of the existing network – with specific focus on SAIDI and SAIFI.

The purpose of this study was to inform the operationally achievable performance levels of the network subject to the existing infrastructural and operational characteristics.

Approach

As mentioned in the introduction, a different approach was followed for this study whereby the expected performance of a network is modelled, given the specific network topology, customer numbers, operating environment etc.

Several software packages are commercially available for reliability modelling of electrical networks, e.g. PowerFactory, PSS/E, etc. These software packages require detailed network models to model the expected reliability of power networks. City Power network planners use PowerFactory for the modelling of all HV networks, but the City Power MV networks are not yet entered into PowerFactory. Furthermore, PowerFactory is not capable of modelling the reliability of all the different substation configurations typically associated with these networks. Although a high level of accuracy is obtained by modelling with the specific software packages mentioned, significant investment and effort is required to create such models, especially when large utility-scale networks are modelled. Subsequently, an alternative approach had to be considered from a resource and information availability and time perspective.

This project made use of a simplified approach to reliability modelling, developed for Eskom Distribution over the period 2008 to 2012 (refer to [1 – 6]). The approach recognises that, from first principles, certain key network components like length of line, number of transformers, location of fuses and breakers etc. have a significant impact on the reliability of a feeder and/or substation. Reasonable assumptions are made regarding the failure rates, maintenance frequencies, travel times and repair times, specific to the City Power context (considering e.g. differences in high density urban versus less dense rural type environments within the City Power service area), and relevant implications associated with the different components. A key assumption is that the City Power networks are reasonably maintained[1] and operated. The number of components of each type and the relevant assumptions are then used in the simplified approach to calculate the expected downtime experienced by customers supplied on different points of the network.

The outcomes from this approach therefore provide the designed "realistically expected" performance base for the City Power network.

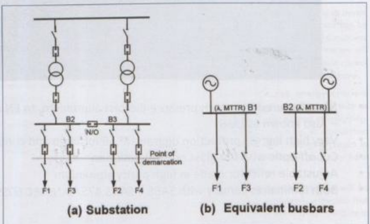


Fig. 1: Reducing a substation to a busbar with equivalent unavailability (adapted from [7]).

Note 1: This assumption may not hold true in all instances, but actual network performance needs to be compared to the "ideal but realistic" expected performance (i.e. factoring in the topographical and environmental realities).

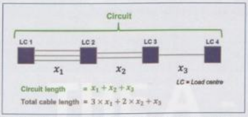


Fig. 2: Diagram illustrating cable exposure to common mode failures.

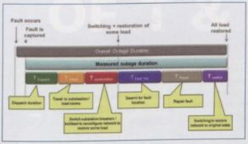


Fig. 3: Outage duration components associated with MV feeder outages.

Fig. 4: City Power sub-transmission and distribution networks.

Modelling methodology

The reliability modelling was split into two separate modelling steps, i.e.:

(a) Sub-transmission network modelling, including all substations and feeders ≥ 20 kV.

(b) Distribution network modelling, including all feeders ≤ 20 kV.

Both these modelling steps are described in more detail below.

Sub-transmission modelling methodology

A decoupled approach was used for the modelling of the sub-transmission network [7, 8]. This approach decouples the contribution of substation events from the sub-transmission line reliability assessment. The point of demarcation between the substation and the sub-transmission lines was defined between the feeder breaker and the line isolator (see Fig. 1).

As a first step, a detailed model of the substation is created. A reliability analysis is then performed on this substation and an annual outage frequency and annual outage duration is produced for the downstream busbar of each substation. This is illustrated in Fig. 1, where the substation shown in (a) is replaced by the equivalent busbar in (b).

The next step is to generate an equivalent system model by replacing all substations with a busbar, of which the outage frequency and outage duration are equal to those of the substation equivalent. This equivalent system model is then used to calculate the reliability of the overall sub-transmission system.

Substation reliability calculation

The substation reliability calculation considers a detailed model of the substation, including the number of components in each substation, how the components are connected (i.e. the configuration), the associated failure rate and repair times of each of the components, and the customers impacted by each failure, as determined by the normal operating conditions and protection philosophies applied on the network [6]. The sub-transmission model makes provision for nine standard busbar configurations, and each of the City Power substation busbars were classified according to these nine standard configurations[2].

Planned maintenance requirements were also considered when calculating the total outage duration experienced by the customer.

Sub-transmission line reliability calculation

Failures of the line and the line isolators were considered for the sub-transmission line calculation. The annual downtime experienced by a customer supplied from a radial network is calculated using the following equation:

$$\begin{aligned} U_{line} =\ & [(\lambda_{line} \times LL) \times (T_{dispatch} + T_{travel} \\ & + T_{switch} + R_{line})] \\ & + [(2 \times \lambda_{line}) \times (T_{dispatch} + T_{travel} \\ & + T_{switch} + R_{isolator})] \end{aligned} \quad [1]$$

where:

U_{line}	=	Outage duration (per annum) of the line/cable module (h/a)
λ_{line}	=	Failure rate of the line/cable (occ/km/a)
LL:	=	Line length (km)
$\lambda_{isolator}$	=	Failure rate of the line isolator (occ/a)
$T_{dispatch}$	=	Dispatch time (h)
T_{travel}	=	Travel time (h)
T_{switch}	=	Switching time (h)
R_{line}	=	Repair time of the line (h)
$R_{isolator}$	=	Repair time of the isolator (h)

Sub-transmission network reliability calculation

If overlapping failures are ignored, the total outage duration at a specific busbar is the sum of the outage duration due to substation faults and line faults. This is illustrated by Eqn 2:

$$U_{Tx} = U_{substation} + U_{line} \quad [2]$$

Note 2: If the actual busbar configuration did not correspond with any of the standard configurations, then the busbar was classified as the busbar type that corresponds most closely to the reliability measure of the actual configuration.

where:

U_{line} = Outage duration experienced due to outages on the sub-transmission lines

$U_{substation}$ = Outage duration experienced due to outages on the substation equipment

U_{Tx} = Outage duration experienced due to outages on the sub-transmission network

Distribution network methodology

This section provides more information on the methodology used to model the distribution network (including all feeders ≤ 20 kV).

Equipment count

The City Power distribution networks consist mainly of two different equipment types, i.e. cables and load centres. Each load centre consists of different components that can fail and result in an outage on a feeder. The following assumptions were made to derive the number of components from the number of load centres:

- Each load centre contains an isolator
- Load centres that supply customers also contain a transformer and a fuse
- There are no breakers in the load centres

Failure rates

Reasonable assumptions were made for the equipment failure rates. These assumptions are based on the expectation that the City Power networks are reasonably maintained and operated. Failure rates for lines and cables are assigned per kilometre, with a realisation that a longer line or cable would have a higher exposure to faults.

Cable exposure

In a typical urban electrical network, electric power cables contribute most towards expected annual faults and fault durations due to the high proportion of network constructed using cables.

Cable networks tend to contain a number of sections where more than one cable may be connected in parallel between two nodes (see Fig. 2). Parallel cables (denoted by $x_1 \ldots x_3$ in Fig. 2) are laid in close proximity, or the cables are connected to the same switching device to isolate the cables in parallel. The customers (connected to load centres denoted as LC1…LC4 in Fig. 2) are therefore exposed to faults on all parallel sections of the cable. Consider the cable network illustrated in Fig. 2.

The total length of cable that each customer is exposed to is:

$$Total\ cable\ length = 3 \times x_1 + 2 \times x_2 + x_3 \quad [3]$$

Equipment count	Load centre mapping
# Breakers	0
# Transformers	# Load centres with customers allocated
# Fuses	# Transformers
# Isolators	# Load centres

Table 1: Distribution circuit asset data assumption.

Considering an equal equipment distribution (i.e. $x_1 = x_2 = x_3$) Eqn 3 simplifies to:

$$Table\ cable\ length = 6 \times x_1 \quad [4]$$

Equipment distribution

The simplified reliability modelling approach ignores the actual contribution of customers and equipment along the length of the feeder. An evenly distributed model is considered, which means that all components, e.g. load centres, are distributed homogenously along the length of the feeder and all customers are distributed homogenously beyond all load centres[3].

Outage duration

The total outage duration per fault can be broken down into smaller components, as illustrated in Fig. 3. Each of these time components is discussed briefly below.

- *Dispatch*

This is the (reasonable) duration from the moment the fault is logged in the system (through either a customer call or a signal from a remote terminal unit (RTU) in the substation), until an operator starts travelling to site.

- *Travel*

This is the (reasonable) time required by the operator to drive to the substation. Different times were assumed for different depots, considering factors such as the average travelling distance between the depot and the substations as well as the expected average travelling speed.

- *Sectionalising*

The (reasonable) sectionalising time represents the time required to create open points and/or switch the backfeed point, in order to restore supply to those customers that are not supplied from the faulty part of the network.

- *Fault find*

This is the (reasonable) time required to identify the faulty piece of equipment, i.e. the time that elapses from the moment the operator arrives on site until he can start with the equipment repair.

- *Repair*

This is the (reasonable) time required to repair/replace the faulty piece of equipment. Different repair times are assumed for different pieces of equipment.

- *Switch*

After the faulty piece of equipment has been repaired/replaced, the network needs to be switched to normal. This time is referred to as the (reasonable) switching time.

The sum of these time components represents the total outage duration experienced by a customer for the full duration of the fault.

Customer restoration factor

Supply can be restored to some of the interrupted customers before the failed component is repaired. The percentage of customers that can be restored depends on the isolating equipment, backfeed-ability and configuration of the network. This percentage is referred to as the "customer restoration factor". The customer restoration factor has no impact on the customers interrupted during the dispatch, travel and sectionalising duration, but it affects the customers interrupted during the fault find, repair and switching duration.

SAIDI and SAIFI algorithm

An algorithm to determine the SAIDI and SAIFI for a specific feeder was derived for both planned and unplanned outages. The algorithms for unplanned outages are discussed next.

The unplanned SAIFI algorithm for a feeder with fuses but without reclosers (or similar protection devices), is shown in Eqn 5:

$$SAIFI_{unpl\_fdr} = (\#Cable \times FR_C + \#Fuses \times FR_F + \#Discs \times FR_D) + \left(\frac{\#Trfrs}{\#Fuses} \times FR_T\right) \quad [5]$$

where:

$SAIFI_{unpl\_fdr}$ = Unplanned SAIFI for a specific feeder

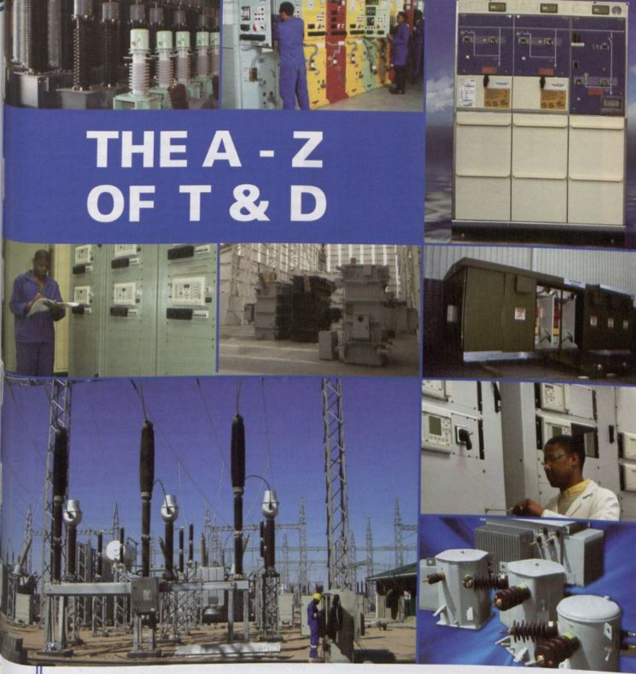
#Cable = Total cable length of feeder (km)

#Trfrs = Number of transformers on feeder

#Fuses = Number of fuses on feeder

#Discs = Number of isolators on feeder

Note 3: This assumption can be changed if relevant customer distribution and positioning data is available. However, in most cases it is not readily available, hence the need for this approach.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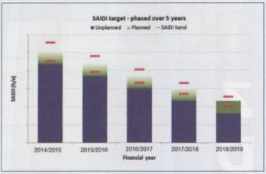

Fig. 5: Illustrative SAIDI target for the next five years.

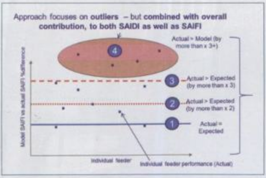

Fig. 6: Approach to identify outliers relative to expected performance [5].

FR_T = Transformer failure rate (occ/a)

FR_C = Cable failure rate (occ/km/a)

FR_F = Fuse failure rate (occ/a)

FR_D = Isolator failure rate (occ/a)

The unplanned SAIDI algorithm is similar to the SAIFI algorithm, but includes the outage duration. The unplanned SAIDI algorithm for a feeder with fuses but without reclosers (or similar protection devices), is shown in Eqn 6:

$$SAIDI_{unpl\_fdr} = [(\#Cable \times FR_C) + \#Fuses \times FR_F + \#Discs \times FR_D + \left(\frac{\#Trfrs}{\#Fuses} \times FR_T\right)] \times T_{response} + [(\#Cable \times FR_C \times Rtime_C + \#Fuses \times FR_F \times Rtime_F + \#\,Discs \times FR_D \times Rtime_D) + \left(\frac{\#Trfrs}{\#Fuses} \times FR_T \times Rtime_T\right)] \times (1 - CRF) \quad [6]$$

where:

$SAIDI_{unpl\_fdr}$ = Unplanned SAIDI for a specific feeder

$\#Cable$ = Total cable length of feeder (km)

$\#Trfrs$ = Number of transformers on feeder

$\#Fuses$ = Number of fuses on feeder

$\#Discs$ = Number of isolators on feeder

FR_T = Transformer failure rate (occ/a)

FR_C = Cable failure rate (occ/km/a)

FR_F = Fuse failure rate (occ/a)

FR_D = Isolator failure rate (occ/a)

CRF = Customer restoration factor

$T_{response}$ = The sum of the dispatch, travel and sectionalising time

$Rtime_T$ = The sum of the fault find, transformer repair and switch time

$Rtime_C$ = The sum of the fault find, cable repair and switch time

$Rtime_F$ = The sum of the fault find, fuse repair and switch time

$Rtime_D$ = The sum of the fault find, isolator repair and switch time

The total outage duration that a customer experiences due to outages on the MV feeder is therefore the sum of the outage durations experienced due to planned and unplanned outages. This is shown in Eqn 7.

$$U_{Dx} = SAIDI_{unpl\_fdr} + SAIDI_{pl\_fdr} \quad [7]$$

where:

$SAIDI_{unpl\_fdr}$ = Unplanned SAIDI for a specific feeder

$SAIDI_{pl\_fdr}$ = Planned SAIDI for a specific feeder

U_{Dx} = Total outage duration experienced due to outages on the MV feeders

Total outage duration

The total outage duration experienced by a customer can now be calculated by combining the contribution of both the sub-transmission network and the distribution network. This is illustrated in Eqn 8.

$$U_{Total} = U_{Tx} + U_{Dx} \quad [8]$$

where:

U_{Tx} = Outage duration experienced due to outages on the sub-transmission network (see Eqn 2)

U_{Dx} = Outage duration experienced due to outages on the distribution network (see Eqn 7)

U_{Total} = Total outage duration experienced by a customer

System-level reliability

The approach explained above was used to calculate the "realistically expected" SAIDI and SAIFI of City Power's entire network (depicted in Fig. 4); this includes more than 100 substations (373 busbars), 276 station transformers, an installed capacity of more than 10 000 MVA, more than 7000 km of MV cable, 14 735 load centres and more than 300 000 customers.

This expected performance was used to derive the following valuable executive decision support outcomes:

- Informed setting of network performance targets for the next five years (in terms of relevant measures such as SAIDI, SAIFI etc.).
- Informed the development of system-level criticality maps to understand which networks are performing worse than expected and where to focus efforts for best"network performance improvement returns".
- Determine the impact of different performance improvement interventions on the network to assist in the development of an improvement strategy, considering cost and performance improvement trade offs.

Each of these decision support outcomes is discussed briefly below.

Setting performance targets

The modelled system target outcomes were used to determine City Power's performance targets for the next financial year. The realistic designed performance was less than the actual performance in 2012/2013, but further investigation and planning is required to improve the performance of those feeders which actual performance is much worse than the realistically expected performance.

City Power therefore considered a phased approach, whereby improvement towards the designed performance level is achieved over a five-year period. For the first round, a simplistic linear improvement from the existing performance levels to the targeted performance levels was used to determine the performance target for each financial year. Such a phased approach is illustrated in Fig. 5. A 10% error band is shown, to accommodate any changes in the assumptions and/or corrections of network data.

Criticality maps

The actual performance of each individual, modelled feeder was compared to its expected modelled performance. A method of relative comparison was used to flag problematic feeders. Various assumptions were made in the modelling approach and therefore some error was allowed between the actual and expected SAIDI, to allow for differences that could be caused by the modelling assumptions and/or data deficiencies. A feeder was flagged as problematic only if the reported annual SAIDI was more than three times the expected SAIDI. This approach is illustrated in Fig. 6.

All feeders identified through this approach were highlighted spatially and a criticality map (see Fig. 7) was developed. It is clear from this map that the problematic feeders are geographically grouped together, highlighting particular geographical areas that require specific focus in order to improve the performance.

Impact of different performance improvement interventions

City Power has identified specific performance improvement interventions to improve the performance of their networks. The simplified approach was used to model the expected performance improvement that each intervention could potentially have. Each intervention is discussed briefly below:

- *Change the dispatch time*

City Power is currently experiencing a longer dispatch time than can be reasonably expected. It is estimated that this dispatch duration can be reduced by almost 90%. The scenario modelled used a dispatch time of 12.5% of the current estimated dispatch time.

- *Build test branch capacity*

Long outage durations are currently being experienced with cable faults, due to limited capacity in the cable test branch department. If additional capacity is built in this department, it is surmised that the cable repair durations can reduce by up to 50%.

- *Improve the customer restoration factor (CR factor)*

The City Power networks have a high level of interconnectivity. A large percentage of the customer base interrupted by an outage can therefore be supplied via an interconnector while the network fault is being repaired. However, operators do not always make use of these interconnectors due to the additional effort required with the switching of the networks. A scenario was modelled where the customer restoration factor is increased from 80 to 95% as a result of the effective application of interconnections.

The modelled outcomes of these interventions are shown in Fig. 8. This figure shows that the identified interventions can reduce the expected City Power SAIDI by 67% if all other parameters are kept constant. City Power network performance engineers can use these results to make an informed decision on where to invest, in order to improve network performance going forward.

Summary and conclusion

The value of this simplified modelling approach can be explained as follows:

By understanding the realistically expected, designed level of performance, resources can be correctly focused and applied to make a difference where the most return on effort and investment would be achieved.

Although a high level of accuracy is obtained using PowerFactory, this simplified modelling approach enabled City Power to determine the expected "as-designed" performance of all their networks in less than four months and with a relatively low financial investment.

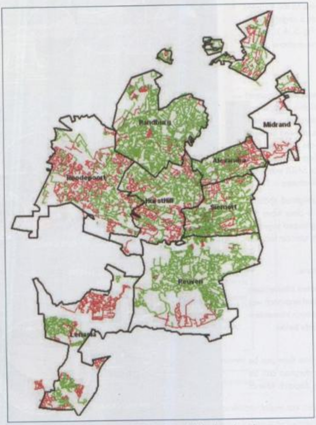

Fig.7: Criticality map, indicating in red all feeders where the actual SAIDI is much worse than the expected SAIDI.

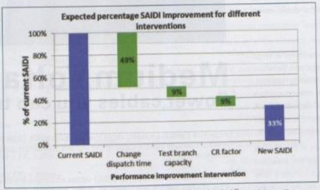

Fig. 8: Expected percentage SAIDI improvement achieved with different interventions.

In cases where the expected designed performance is inherently much worse than City Power's stakeholders' expectations, informed decisions can be made regarding potential design changes and capital and refurbishment investment requirements to move such infrastructure performance levels to expected levels.

By modelling the networks, the network performance engineers develop a better understanding of what performance levers and geographical areas require additional focus to achieve the best overall system-level network performance.

The approach highlights potential deficiencies in network information and data. This data is crucial for proper management of the networks and can help guide efforts to improve specific elements, which in turn will also assist with improved overall decision-making and day-to-day operational management.

By using this modelled approach, it is possible to develop cost- and time-effective "what if" scenarios that can support better-informed strategic, executive and tactical decision-making about network performance, investment decisions and future potential network developments.

The approach developed is generic in nature and can be applied in any electrical distribution utility, with a relatively small investment in terms of resources and with minimal detailed technical information.

Acknowledgements

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Local government develops technical scarce skills for road to professional registration

by Mvuleni Bukula, Nelson Mandela Bay Municipality

An overview of the Infrastructure Skills Development Grant (ISDG) Mentorship Programme as rolled out by the Department of National Treasury and implemented by the Eastern Cape Province beneficiary municipalities in an attempt to professionalise and strengthen local government skills capacity in order to ensure sustainability and delivery of infrastructure.

South Africa two decades into democracy has made significant progress in both economic and social development but continues to face difficult challenges with respect to providing a better quality of life for its people. The Department of Cooperative Governance and Traditional Affairs (COGTA) has highlighted skills shortage and technical capacity (i.e. lack of engineers, technologists and artisans) as some of the problems that are hindering municipalities from delivering on infrastructure. This has led to the infrastructure deteriorating into a state of disrepair. Thus, central to the success of government's 2030 vision will be to build and develop adequate technical capacity, in order for local government to deliver and maintain world class infrastructure service delivery.

To address the above, National Treasury has introduced a new grant for municipalities with the objective of building and improving their technical and management abilities in the delivery of infrastructure. The grant is aligned to the national outcomes and is designed in such a way that it supports Outcome 5 "A skilled and capable workforce to support an inclusive growth path", and Outcome 9 "A responsive, accountable, effective and efficient government system" [1].

It is one of the strategic support interventions and also a sustainable solution to shift from gap filling practices and curb the shortage of competent and capable, skilled professionals in the built environment. This grant aims at supporting the government drive to encourage municipalities to engage in processes of reforming the built environment, utilising the funding and other investments and the creation of jobs for newly qualified graduates. This is a schedule six grant, known as the Infrastructure Skills Development Grant (ISDG), and its main purpose is to train technicians, technologists and engineers in the built environment until they become professionally registered with recognised professional bodies/councils.

Profession	Category					Total
	Technicians	Technologist	Engineers	Artisan	Other	
Engineering field						
Electrical engineering	17		1			18
Civil engineering	34	2	1			37
Environmental sciences						
GIS	15					15
Quantity surveyor	4					4
Project and construction management						
Construction project management	6					6
Construction health and safety officer					1	1
Property valuations						
Property valuer	3					3
Planning						
Town planning	1					1
Artisan						
Electrician				12		12
Millwright				1		1
Plumber				1		1
Total	80	2	2	14	1	99

Table 1: Details regarding the Eastern Cape ISDG Skills Matrix.

Background

In 2011, the Nelson Mandela Bay Municipality (NMBM) requested funding from National Treasury for the expansion of the Electricity and Energy Directorates skills development programme and full implementation of the grant commenced in January 2013. The NMBM is amongst the first grant recipients to implement the ISDG Mentorship Programme in the Eastern Cape Province.

The roll-out of the ISDG Mentorship Programme in the Eastern Cape necessitated the establishment of a programme management support office in the province. The NMBM, considered to be the forerunner, was requested to also provide strategic support to other local municipalities and a decision was taken to have the programme management support based at NMBM.

To date, the programme has yielded profound results at NMBM, particularly in providing the necessary capacity in areas of scarce skills. The programme has recruited 22 unemployed graduates in the following professions: electrical technicians, construction project managers, geographical information science technologists; and have 21 civil technician bursars, some of which have been with the municipality for just under four years.

The ISDG Mentorship Programme deliverables have been incorporated into the NMBM Integrated Development Plan (IDP) and

Service Delivery Budget Implementation Plan (SDBIP) for the next Medium Term Expenditure Framework (MTEF) period commencing in 2014/15. This has been done in order to monitor successes and any arising challenges of the municipality's strategic level, and to ensure that National Treasury's performance indicators are adhered to.

The ISDG Mentorship Programme has three critical conditions attached to it:

- The training, mentoring and coaching must be provided by accredited service providers and registered professionals in the built environment; the training programmes should be developed by the host municipality approved by the relevant professional body.
- On commencement of their training, it is required that these graduates register as "candidates" with the relevant professional body so that they are professionally registered on completion.
- The training programme is overseen by professionally registered mentors and coaches in that respective profession and the professional body will assist with the quality assurance thereof [2].

The ISDG Mentorship Programme is guided and supported by a steering committee that is composed of statutory council and sector departments. Municipalities gain access to additional professional workforce and thus enhance productivity and efficiency while the graduates augment their qualifications with theory and practical experience. During training, municipalities must follow structured training programmes that meet the requirements of the relevant statutory councils. Upon completion of the training programme and when graduates are successfully registered as professionals within their respective fields, municipalities are expected to absorb them within their respective fields. Municipalities are expected to capitalise on the skills that have been developed [1].

Eastern Cape ISDG skills matrix

Details regarding the Eastern Cape ISDG skills matrix can be seen in Table 1.

Achievements

The ISDG Mentorship Programme has been in operation in the Eastern Cape Province for 18 months now, and as a result, the programme deliverables have advanced to the operationalisation and monitoring of the project implementation. The main focus is currently on providing learner guidance, support and ensuring that workplace training provides opportunities to gain competence through evaluation, consultation and implementation of work. The following activities have ensured that the practical training and professional development of mentees meet the stipulated competencies and standards set by the relevant applicable statutory bodies/councils:

- Established strategic partnership as Eastern Cape municipalities – complementing each municipality's strengths.
- Development of framework to manage multi-professional trainees in the municipality environment.
- Approval of training programme by professional bodies/statutory councils within the profession specific clusters/ workstreams established.
- Incorporation of ISDG Mentorship Programme to IDPs, performance indicators and workplace skills plans (WSP) of the municipalities.
- Training programme is aligned to suitability of training environment and existing projects.
- Training management is centrally co-ordinated for leveraging maximum technical input from different municipalities.
- Quality assurance is done prior to rotating to the next area of training – assessments, ECSA C2.1 form, C2.3 training and experience report form, report, etc.
- Governance structures in place for monitoring and reporting.
- Established strategic relationship with external partners – Eskom, Department of Public Works (DPW), Department of Rural Development and Land Reform, etc.
- Appointment of mentors for all trainees.
- Behavioural assessments for addressing non-technical training competencies and life skills.

Programme successes

Programme management support

The programme support team's presence, across municipalities has assisted them in lying the foundation for the programme, understand the municipality's culture and policies, and ensure that the programme is fully entrenched, amongst other things.

Project governance

The management framework used for implementation ensures that municipalities adhere to grant conditions.

Development of accelerated training programme

Strategic partnerships with professional bodies have ensured standardisation of all training programmes, allowing for seamless integration as per stipulated competencies and standards set.

Strategic partners

Workplace experience is provided by strategic partners who provide suitable training options to meet the stipulated competencies and standards set by statutory bodies.

Inter-municipality memorandum of understanding

In the Eastern Cape Province, Nelson Mandela Bay Municipality, Lukhanji District Municipality and Buffalo City Municipality were amongst the first municipalities to be recipients of the funding for the ISDG Mentorship Programme. The grant was subsequently also granted to

Risks	Mitigation measures
SACPCMP requires trainees to have three years post graduate relevant practical experience for candidate registration meaning they won't be eligible to register as professionals within the funding period.	A meeting was held with the registration council on 28 March 2014 where SACPCMP agreed to assist in formulating a planned programme of mentorship and monitoring to ensure that the candidates upgrade to professional categories within the specified funding period.
Some of the SACPCMP trainees do not have a B-Tech Degree as required by the council.	Mentees to fund their own B-Tech studies so that they can acquire the qualification and be eligible to register with the council.
Professional registration through ECSA requires mentees to submit a project for which they were responsible for from start to finish. Selection and availability of such projects could pose challenging.	The mentors have sent correspondence to the respective departments in order to identify such projects for mentees where possible.
Training is expensive if individually done and where it involves travel and accommodation.	Training is centrally co-ordinated to cater for all ISDG municipality beneficiaries in the Eastern Cape for cost saving and added value.
Supply chain processes are cumbersome and take a much longer time to procure.	Sharing of resources amongst municipalities and upfront procurement of training linked to the training plan. An inter-municipal agreement to formalise collaborations amongst Eastern Cape municipalities which are recipients of the ISDG was adopted and signed.

Table 2: Details of the project challenges and remedial actions.

King Sabata Dalindyebo District Municipality and Alfred Nzo District Municipality.

Whilst operating their separate programmes, the municipalities noticed that within their programmes they had weaknesses which prevented them from fully performing their obligations and that amongst them, some municipalities were stronger in areas they had weaknesses.

An agreement to formalise collaborations amongst Eastern Cape municipalities to share and utilise each other's skills and resources was concluded in August 2014.

Behavioural assessments for non-technical training

Engineers play an important role in a nation's development. In the new millennium, engineers have to face new challenges, which require more than just technical skills. They are expected to be more versatile and possess essential non-technical skills as their work scope will require them to deal with professionals in various disciplines. In addressing this issue of skills mismatch between the graduates produced by institutions of higher learning and the requirements of industry, the NMBM has incorporated behavioural assessments for all graduates as part of its implementation strategy for the ISDG. A competency framework for each profession in line with the provincial and local government's occupational competency framework and data dictionary was developed to provide a personal development plan which will assist each graduate in their training for the duration of the mentorship programme.

The behavioural assessments highlighted the following glaring challenges:

- 24% of students functioning below diploma level.
- 15% learning potential also below diploma level.
- 36% below average emotional intelligence.
- 24% below average english verbal reasoning.
- 42% below numeric reasoning.
- 39% below average abstract reasoning.

In an attempt to address these challenges, the following development actions have been incorporated in the implementation of the ISDG Mentorship Programme:

- Formal development actions:
  - Team development intervention to bind, motivate and inspire as well as develop teamwork and team facilitation skills.
  - Emotional Intelligence Intervention (workshop).
  - Business communication skills e.g. presentation skills, meetings and minute taking, business writing skills etc.
- Informal development actions:
  - Coaching focussing on communication skills.
  - Coaching focussing on organisational commitment and compliance.

Project challenges and remedial actions

Details of the project challenges and remedial actions can be seen in Table 2.

Key programme considerations

- Incorporating existing permanent employees.
- Minimising duplication of effort in government.
- Deep consideration of the training environment – design/construction/ maintenance.
- Formalising the strategic partnerships.
- Professional bodies to be more aggressive in quality assurance.
- Streamlining various training interventions.
- Skills retention strategy – train for country or train to retain.

Lessons learnt

The variety of skills in the programme necessitated the engagement with the respective professional bodies/councils and the packaging of different rules for each due to the nature and complexity involved. This includes finding alternative employment in areas where the municipalities have a challenging environment in doing so.

There are about 32% of the trainees in the ISDG Mentorship Programme who are not hosted in their respective municipalities as these environments will not be able to give sufficient training exposure in preparation for professional registration. They are placed with relevant host employers and this requires close monitoring as there are also challenges in streamlining what they are doing there to the programme deliverables.

The timing of the programme is relevant and the need to provide trained and registered professionals is enormous. Professionalising local government requires a concerted effort and commitment from government, relevant entities, professional bodies and the private sector. The results of skills development can only be realised in the medium to long term, i.e. after the graduates have satisfied the requirements of the relevant professional body.

Unlike other internship programmes, not every municipality has the capacity to host and it becomes necessary to strike partnerships with other public entities to support training.

Host municipalities and entities have a better understanding of training requirements recognised by professional bodies in the built environment.

The programme has to be aligned to other capacity building programmes in local government, such as those programmes driven by bodies like the Municipal Infrastructure Support Agency (MISA) and Local Government Sector Education and Training (LGSETA). This is to ensure that there is no duplication of effort for municipal buy-in and accountability thereof.

Conclusion

Factors that are key for the successful implementation of the ISDG Mentorship Programme are: sound principles, credible data, political commitment, adequate capacity (human, institutional and organisational), adequate and effective monitoring and evaluation, unambiguous assessment criteria and common understanding of goals, targets and indicators.

The roll-out of the ISDG Mentorship Programme has had a tangible and positive impact on accountability, spending and service delivery within local government, and the experience gained and capacity created has developed a solid foundation for impact driven and aligned capacity building.

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Countering the dire shortage of technical personnel in South Africa

by Tom Phillips, Inspired Interfaces

This paper details several challenges being faced by the power industry and will highlight how the judicious use of technology can mitigate against the damaging delays caused by resource shortages and offer solutions to the electricity transmission and distribution industry.

The power industry is under pressure due to the dire shortage of appropriately qualified technical personnel. From artisans to engineers, the industry has seen a decline in numbers making service delivery a very real and present challenge.

Mitigating this shortage we have seen an increase in the usage of various (software) tools aimed at improving productivity and guaranteeing design integrity. There's no substitute for experienced technical personnel, but using design tools which assist engineers in the execution of their duties goes a long way in building confidence and experience.

An overview of some of the tools available for systems integration will give the hard pressed utility planning and projects personnel options on how best to manage their workload. Automating the repetitive operations affords more time for analysis and optimisation and the opportunity to execute other important tasks.

Valuable benefits accompanying the use of software tools include the creation of asset registers (complete with GPS location), customer service information, stock requirements, procurement bills of materials and budget tracking. In addition, alignment with master plans and network development plans can be managed.

The effective deployment of these applications contributes to capacity building within the organisation, and not only mitigates the scarcity of design personnel but improves cost effectiveness, the quality of designs and speed with which they are completed.

Resource issues

The multiplicity of government programmes (AgisSA, Jipsa, etc.) are clearly not achieving the desired results, leaving the country critically short of technical personnel to meet not only current demand but also South Africa's economic grow targets. The failure of the Sectorial Education and Training Authorities (SETAs) to achieve their mandate in training compounds the problem.

The solutions to the deficit being proposed by the authorities will only bear fruit in the medium to long term, necessitating short term solutions being sought today. In the light of the challenges being faced in every engineering discipline in South Africa imaginative, alternative solutions have to be proposed and implemented. These solutions have to meet the short term requirements and bridge the gap between scarcity of suitably qualified resources and getting the job done. Part of this solution is the deployment of specific software tools available in the open market.

These tools can never replace expertise and experience but do offer the over-worked engineer, technician and planning officer the ability to get the necessary work completed in the shortest period and with a minimum of fuss.

Our present situation

First let's put some disquieting facts and figures on the table. The World Economic Forum Global Information Technology report (2013 – 2014) ranks the quality of South Africa's education system 140th out of 144, and our mathematics and science 143rd out of 144 countries [1]. This is not the most ideal foundation for the creation of our country's necessary technical resources.

Compounding the scarcity of learners with a scientific and mathematical background emerging from high school is the fact that SETAs have not been performing, and in particular the Electrical SETA. Table 1 shows company responses to questions raised regarding the effectiveness of SETAs (1 = SETAs are doing a poor job, and 5 = SETAs are doing a good job to a large extent).

Highlighting the disastrous state of artisan training in South Africa's electrical sector, Mark Mfikoe, ECA(SA) National director argues, "In my view the biggest scandal in this country is the compromising of our capacity to develop scarce skills for this industry and others as a result of the shocking manner in which our mandated training authorities continue to fail the country". He states further, "The energy SETA was placed under administration and the electrical contracting industry was transferred to the construction SETA, and before you could wink, the construction SETA was itself placed under administration and still is" [5].

Further compounding the resource shortages Nick du Plessis suggests, "As it stands the industry has a large contingent of an older generation of artisans. There are younger people coming through, but the layer comprising people aged, say, late 20s to late 40s is very thinly populated. Training and workplace factors across the country have been in part responsible for this situation, as has immigration, with many artisans having left the country due to their skills being

Services	1	2	3	4	5	Could not comment
	%	%	%	%	%	%
Advice and support (learnerships)	34,5	9,8	18,0	8,2	4,1	25,3
Easy submission procedures	30,9	7,2	21,6	7,7	3,6	28,9
Internet site and web pages	35,1	8,8	15,5	4,1	4,6	32,0
Promptness in paying grants	33,0	7,7	15,5	3,1	3,1	37,6
Providing information about courses, programmes and training	32,5	8,8	21,6	6,7	5,2	25,3
Providing information about grants	35,1	9,8	20,6	4,6	2,6	27,3
Providing sector skills plans	40,2	9,8	14,4	3,6	2,6	29,4
Provision of free training not funded by employers	40,2	8,8	12,4	5,2	3,1	30,4
Response to queries	32,5	6,2	17,0	5,2	3,6	32,5

Table 1: Satisfaction with the services of SETAs rendered (2002 to 2003) [3].

in high demand internationally" [8]. The paper, "Engineering skills – key to effective service delivery" speaks of the collapse of artisanal training with the registered artisan's average age being 55 years [2]. What we have is an abundance of aging qualified and experienced individuals with no-one to mentor or pass the baton on to so to speak.

From the HSRC report it is clearly evident that there is an undersupply in electrical and industrial engineers. Furthermore, the shortage of engineers from previously disadvantaged backgrounds remains strong and that these personnel are in high demand [9].

Amidst all these challenges the power industry, utilities and municipalities continue to deliver on their service delivery mandate, but with fewer personnel carrying a heavy load. Municipalities, large corporates, and consulting firms continue to undertake small, medium and large projects. South Africa's engineering and technical versatility has seen many of our entrepreneurs (and corporates) spread their wings north of the Limpopo. It is interesting to note that in many of the contracts being undertaken off shore there are foreign based ex-South African technical (and managerial) personnel involved in these organisations, working alongside their South African counterparts. Visiting Jacobs Engineering Group in Perth, Australia during 2012 it was astounding to see that the majority of the projects, planning and design engineers were South African.

Solutions for transmission and distribution network planning and designers

The picture painted above is one that plagues the entire country, but our focus is on the power industry. What follows is a short discourse on software solutions which relate predominantly to those performing electrical transmission and distribution network planning, design and analysis.

For the personnel involved in the planning, design, analysis and implementation of electrical transmission and distribution networks help is at hand in the form of several powerful software packages. Some are more user friendly, some more integrated, while others focus on very specific aspects of electrical network design and analysis.

Many of the larger international corporates involved in network design and analysis have (over the years) developed their own proprietary software systems which are inextricably linked to their business processes and procedures. These products are not generally marketed to the local industry.

The design and analysis software systems available to the designers vary dramatically in complexity, as does their functionality and cost of ownership. I use the word ownership because these software applications are seldom purchased outright, but rather there is some form of annual maintenance or technical support agreement.

Local support and training is mandatory to get the most out of the packages. Like mobile telephones, one generally uses only a fraction of the true functionality and power of the devices – so too with the design and analysis software packages.

The supporting/peripheral software products, such as geospatial data systems (GIS), database systems (using either Microsoft SQL or Oracle) and computer aided design (CAD) packages (offering both 2D and 3D representation), though integral to the modelling and analysis packages being discussed will simply be mentioned. The most commonly used CAD packages are AutoCAD and Bentley.

Table 2 highlights the most commonly used electricity transmission and distribution network design and analysis software in South Africa.

User friendliness of the design software varies dramatically between packages. While some are intuitive and the user can be up and running within minutes, others are more complex and require a fair degree of familiarisation before attempting to design and model a network. The more expensive products require a comprehensive amount of elemental technical data to be captured prior to simulation, often more than is available from even the manufacturer of the particular item, whether it be a cable, a motor, a capacitor or a transformer. In these circumstances the hard pressed designer has to guess the parameters, and he/she is often not in a position to make these estimates.

The one thing all the design packages do well is perform repetitive, laborious calculations incredibly quickly. Complex networks can be designed, analysed and verified very quickly.

Furthermore, the execution speed affords the designer time to play with "what-if" scenarios and perform network optimisation calculations. Some of the packages even have this optimisation functionality built in.

A feature that exploits the computational power of the computer is the analysis of multiple (induction) motor starting (Fig. 1). By

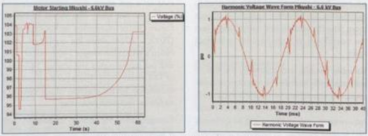

Fig. 1: Features which exploit computational power.

DigSilent PowerFactory	DigSilent has a comprehensive suite of power system products, with its PowerFactory being a highly integrated software package.
ETAP	ETAP is a fully integrated AC and DC electrical power system analysis tool with many modules offering functionality to suit.
ReticMaster PowaMaster PowerOffice	Inspired Interfaces' software product suite is highly integrated and user friendly. The suite includes auto-generation of bills-of-quantities and costed bills-of-materials.
DesignBase	Paladin software's DesignBase is a modular electrical system design and simulation package.
Dapper Captor	SKM offer modules for three-phase power systems design and analysis, and software to coordinate protection device discrimination amongst several others.
CYMDIST PSAF	CYME engineering software solution is a module based package that covers distribution, transmission, protection and several other applications for power engineering solutions.
My Ecodial L Rapsody ID-Spec Large	Schneider Electric's products include tertiary and industrial building electrical installation design software, LV electrical installation calculation aids and software to design modular and functional low voltage switchboards.

Table 2: Commonly used electrical transmission and distribution network design software.

hand this is at best an estimation, but in the packages that feature this functionality it can be tuned to the nth degree. An absolute bonus when planning and designing industrial installations with multiple motors, variable speed drives and other non-linear loads. The analysis software affords the designer the opportunity to test and create optimum motor starting regimes.

Associated with the motor starting analysis benefits is the ability of some packages to perform harmonic modelling and analysis of the network. This facilitates the design of network filters to reduce the undesirable effects of these harmonics.

Core functionality to all the modelling and simulation packages are; load flow analysis, voltage drop calculation, current flow analysis, energy loss calculation, network balancing and fault current analysis. Several packages also include load profile analysis to assist with capacity planning. Several software vendors include the integration of protection devices whereby the package can assist with the design of appropriate discrimination. Furthermore, some packages incorporate conductor optimisation where the designer can design the most cost effective networks.

The most of the popular software packages offer a systems approach to design, some more effective than others. This linked functionality includes loading survey data for accurate as-built models or proposed network extensions, while others offer GIS integration and database management.

The power of these software packages can take a designer from raw field survey data to a completed, electrically validated and optimised design in a very short space of time. This frees the hard pressed designer to perform other duties.

There are software packages that offer project management and scheduling modules, while others include the creation of comprehensive bills of quantities and costed bills of material. It is not within the scope of this paper to go into the peripheral packages though.

Having expounded on what these excellent design packages can do we come back to the reason for this discussion, the critical resources shortages and inadequacy of training and mentoring. Many of the designers are ill-equipped to carry out the tasks demanded of them. This puts them in the precarious position of undertaking designs while not having the necessary wherewithal to instinctively spot errors and potential network failures. This is where it is imperative to have the right supervision and mentors to show them the best practices and guide the technical personnel in their designs (easier said than done).

Value added benefits

The incorporation of designs onto GIS/topographical maps facilitates the visualisation of the network and can ensure mistakes are not made, such as poles in the middle of rivers or dams, pole stays placed in the road, or cable spans running through buildings, to name but a few common errors.

Additional benefits include accurate asset registration, location and management. Once networks are completed it is very simple to create and manage an asset database of all the assets (Fig. 2), complete with GPS locations. This further assists technical services personnel when attending to customer queries and field fault reports.

Furthermore, the assets database makes the creation of maintenance regimens simple, particularly when it comes to transformers, HV insulators and the like. Technical personnel can easily compile works schedules for this maintenance, replete with asset GPS location. Once a network has been designed and captured into the network design package(s) analysing the constraints associated with line extensions and the addition of new loads is simple. Analysis also quickly highlights any marginal or overloading conditions, whether they are transformers being overloaded or cable capacity issues.

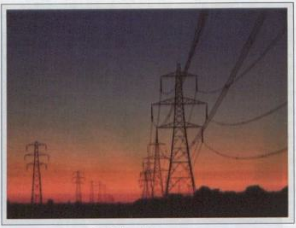

Fig. 2: Electrical assets.

Fig. 3: Aerial view of assets.

Conclusions

Let us not sugar coat the situation we have in the electrical power industry in South Africa. We have challenges, economic, skills and personnel related that have to be tackled head-on. The hemorrhaging of highly skilled and qualified engineers, technicians and artisans from our shores has left a void that is not easily filled. Fewer skilled professionals mean fewer young engineers and artisans can be mentored and brought up through the ranks. Compounding the exodus of precious skilled personnel is the failure of our education system to train sufficient learners in the all-important sciences and mathematics.

There is no substitute for experience, but the judicious use of technology goes some way to alleviating the pressure the technical personnel are under.

It is imperative for South Africa to reverse the downward economic trend. The power industry cannot wait for the government and quasi-government organisations to find their way out of the quagmire. The industry has to take bold action to redress the shortcomings of the past and to be the catalyst for growth. In a recent AMEU meeting a counselor took an Eskom representative to task for their failure to meet the capacity demands in South Africa, calling on Eskom to take responsibility for their part in the poorer than expected growth figures for the country and to stop acting like a victim rather than one of the causes of the country's distress.

Using the modelling and design software packages assists with network design accuracy, reliability, consistency and the use of standardised materials.

I'd like to leave the reader with a sobering thought that may seem to fly in the face of the skills shortage argument and negate the need for design tools that make work quicker, easier and more accurate. The reality is that there are dramatic changes in South Africa's economic situation. South Africa is slowly losing its "powerhouse of Africa" status to countries to the north, in particular Nigeria. While the rest of the world is (cautiously) focusing on Africa for investment, South Africa's credit rating is showing a negative trend. The scale of investment from Europe, America, China and Japan is impressive, but unfortunately the lion's share of this investment is headed north of the Limpopo.

Those familiar with Clem Sunter's scenario planning flag system may recall that in June 2012 he adjusted the percentages of the latest South Africa's scenarios: Premier league, second division and failed state from 70%-30%-0% to 50%-40%-10%. In the discourse he pronounces that going into the second division would mean South Africa would probably lose its position in BRICS, access to international funds would become problematic and Nigeria would overtake South Africa as Africa's largest economy by 2020 [6]. While SA is still a member of BRICS, Nigeria has overtaken it as Africa's largest economy – six years ahead of schedule.

To add to this, we are seeing large corporates divesting their interests in South Africa, the latest being BHP Billiton divestment of their nickel, aluminum and other assets.

We are witnessing widespread budget cuts and project postponements/cancellations. Anyone in the consulting and construction industry will attest to this. As a result, local companies are being forced to look for work elsewhere – and where better but to look into Africa. We have the inside track on the challenges of doing business in Africa, but it's getting crowded.

In the final analysis there is a solution to the dire shortage of suitably skilled resources in transmission and distribution network planning and design in the form of the judicial deployment of these powerful software tools. Designs implemented using network analysis software are generally delivered quicker, more accurate, better optimised and cost effective.

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AMEU Affiliate Members

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Deceased Engineering Members 2014	
Alton Lock	Gordon Davies

AMEU Past Presidents

Date	Name	City	Date	Name	City	Date	Name	City
1915 – 1917	JH Dobson	Johannesburg	1948 – 1949	A Forden	East London	1975 – 1977	E de C Pretorius	Potchefstroom
1917 – 1918	J Roberts	Durban	1949 – 1950	DA Bradley	Port Elizabeth	1977 – 1979	KG Robson	East London
1919 – 1920	B Sankey	Port Elizabeth	1950 – 1951	CR Halle	Pietermaritzburg	1979 – 1981	PJ Botes	Roodepoort
1920 – 1922	TC Wolley Dodd	Pretoria	1951 – 1952	JC Downey	Springs	1981 – 1983	DH Fraser	Durban
1922 – 1924	GH Swingler	Cape Town	1952 – 1953	AR Sibson	Bulawayo	1983 – 1985	W Barnard	Johannesburg
1924 – 1926	J Roberts	Durban	1953 – 1954	JC Fraser	Johannesburg	1985 – 1987	JA Loubser	Benoni
1926 – 1927	B Sankey	Johannesburg	1954 – 1955	GJ Muller	Bloemfontein	1987 – 1989	AHL Fortman	Boksburg
1927 – 1929	J Mordy Lambe	East London	1955 – 1956	DJ Hugo	Pretoria	1989 – 1991	FLU Daniel	Cape Town
1929 – 1931	R Macauley	Bloemfontein	1956 – 1957	JE Mitchell	Bulawayo	1991 – 1993	CE Adams	Port Elizabeth
1931 – 1933	LL Horrel	Pretoria	1957 – 1958	JL van der Walt	Krugersdorp	1993 – 1995	HR Whitehead	Durban
1933 – 1934	LF Bickell	Port Elizabeth	1958 – 1959	CG Downie	Cape Town	1995 – 1997	JG Malan	Kempton Park
1934 – 1935	AR Metelerkamp	Bulawayo	1959 – 1960	R Wcone	Johannesburg	1997 – 1999	HD Beck	East London
1935 – 1936	GG Ewer	Pietermaritzburg	1960 – 1961	RMO Simpson	Durban	1999 – 2001	AJ van der Merwe	Bloemfontein
1936 – 1937	A Rodwell	Johannesburg	1961 – 1962	C Lombard	Germiston	2001 – 2003	J Ehrich	Pretoria
1937 – 1938	JH Gyles	Durban	1962 – 1963	PA Giles	East London	2003 – 2004	PE Fowles	Pietermaritzburg
1938 – 1939	HA Eastman	Cape Town	1963 – 1964	JC Downey	Springs	2004 – 2006	D Potgieter	Polokwane
1940 – 1944	LJ Nocholas	Umtata	1964 – 1965	RW Barton	Welkom	2006 – 2007	V Padayachee	Johannesburg
1944 – 1945	A Rodwell	Durban	1965 – 1967	D Murray-Nobbs	Port Elizabeth	2007 – 2008	S Maphumulo	Durban
1945	JS Clinton	Harare	1967 – 1969	GC Theron	Vanderbijlpark	2008 – 2010	S Gourrah	Buffalo City
1945 – 1946	JW Phillips	Harare	1969 – 1971	HT Turner	Umtali	2010 – 2012	M Rhode	Drakenstein
1946 – 1947	GJ Muller	Bloemfontein	1971 – 1973	JK von Ahlften	East London	2012 – 2014	JJ Roos	Ekurhuleni
1947 – 1948	C Kinsman	Durban	1973 – 1975	JC Waddy	Pietermaritzburg			

AMEU Honorary Members

Period	Name
1915 – 1936	Dr H J van der Bijl
	J Roberts
	E Poole
1938	LL Horrel
1944	GH Swingler
	AT Rodwell
1950	Dr. JH Dobson
1951	HA Eastman
1955	W Ballad-Ellis
	JC Fraser
	C Kinsman
1956	WH Milton
	A Morton Jaffray
	Major SG Redman
	Clr. CEK Young
1957	DA Bradley
1958	Col. GG Ewer
	A Foden
	Clr. Halley
1960	Clr. FJ Castelyn
	Clr. LP Davies
1962	AR Simpson
1963	CG Downie
	JC Downey
	RW Kane
1965	G Muller
1967	Clr. JD Marais
	JR Telles
1969	W Beesley
	PA Giles
	D Murray-Nobbs
	EL Smith

Period	Name
1971	DJ Hugo
	ACT Frantz
	HT Turner
	R Leishman
	RMO Simpson
	W Rossler
	F Stephens
	JF Lategan
1973	RG Ewing
1975	Clr. HG Kipling
	C Lombard
	DC Plowden
	JG Wannenberg
1977	Dr. RL Straszacker
	AA Middlecote
	GC Theron
	JC Waddy
1979	RW Barton
	Clr. HJ Hugo
1981	JDN van Wyk
	Dr. RB Anderson
	J Morrison
1983	TC Marsh
1985	AA Welch
	KG Robson
	Clr. RL de Lange
	W Barnard
1987	AP Burger
	JC Dawson
	DH Fraser
	PC Palser
1989	PJ Botes
	MPP Clarke
	EG Davies
	JA Loubser

Period	Name
1993	FLU Daniel
	JE Heydenrych
	B van der Walt
1995	CE Adams
	B Madeley
1997	JD Algera
	HR Whitehead
	F van der Velde
1999	JG Malan
	CE Burchell
2003	AJ van der Merwe
2005	PE Fowles
	T van Niekerk
	J Ehrich
2007	DET Potgieter
2008	V Padayachee
2009	S Maphumulo
	JJG Nel
2010	O Bothma
	JE Coetzee
	RS Wallis
2011	M Carry
	D Louw
	H Roos
	S Gourrah
2012	Michael Rhode
	Paul Johnson
	Louis Steyn
	Ferdinand Diener
	Roy Wienand
	Jorge Pereira
2014	Joseph Renney
	Neil Ballantyne
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