AMEU

AMEU Convention 2012
The 63rd AMEU Convention
15 to 17 October 2012

"Solutions for a Smart Industry"

Special AMEU Convention Proceedings edition

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AMEU Proceedings

2012

Modular MV switchgear with shielded solid insulation system

Information from Schneider Electric

Schneider Electric introduces Premset switchgear, the first MV distribution switchgear combining shielded solid insulation system (2SIS) with extreme compactness and complete modularity.

Schneider Electric, a global specialist in energy management, has released Premset switchgear, its smart grid ready MV switchgear with a completely modular design to facilitate easy installation, upgrading, and maintenance.

The switchgear also uses the shielded solid insulation system (2SIS), a breakthrough innovation that protects all the switchgear's live parts to help ensure a safe, trouble-free service life for both operator and equipment.

According to Isaac Kruger, standardisation manager MV at Schneider Electric South Africa, Premset applications can be found in all medium voltage secondary distribution substations, such as in buildings and industry as well as distribution networks.

"While solid insulation has previously been used, Premset switchgear is the first global product using this earth-screened solid insulation. This system reduces the risk of internal arcing, enhances safety and reliability in any environment, and extends the equipment life by up to 30%, with no preventive maintenance nor servicing necessary," he says.

With its three-in-one design, Premset switchgear is said to be the safest and most intuitive switchgear in its class:

- Breaking, disconnection, and earthing functions are all integrated into a single compact three-position device, making it easier to operate.
- SF6-free design uses only vacuum and air technologies.
- Enhanced safety since it's fitted with built-in failsafe interlocks.

Additionally, through advanced monitoring, control, and smart-grid functionality, Premset switchgear helps ensure your network is at its peak performance level, featuring:

- Feeder automation, with switchgear including built-in communication and local intelligence.
- Load management, with integrated smart metering.
- Asset management, with advanced switchgear and transformer monitoring.
- VIP self-powered protection and communication relay for higher MV network availability.

And, with its standardised dimensions, reduced footprint, and simple front power connections, both time and money spent installing Premset switchgear are greatly reduced. Every aspect of the system is designed with the intention of reducing total cost of ownership as well as making installation and adaptations as seamless as possible, including:

- Straightforward assembly because identical busbar and cable connections are used for the entire range;
- Easy-to-install patented universal flat power connection system; and
- Extended possibilities for cables entry, with easy connection at a height of 700 mm and a single type of bushing.

"Premset switchgear is a technological breakthrough, opening the way to unprecedented safety, efficiency, and ease of use. That is, it is safe and reliable in any environment as insulation and screening of all live parts ensure a trouble-free service life, while SF6-free technology enhances peace of mind. Also, it is flexible, simple, modular, and functional; it is easy to install and easy to use, with operator-friendly switchgear and no servicing of main units thanks to SSIS technology. Lastly, the switchgear is smart grid ready and offers distributed intelligence, including advanced protection, control and monitoring, fully integrated for higher dependability and energy efficiency," says Kruger.

Upgrading is made simpler, with the same auxiliaries, accessories and monitoring devices being used for the entire range. In fact, this "plug and play" design also allows for on-site additions that do not require any special training, tools or adjustments.

"Since the 1920s, Schneider Electric has been at the forefront of switchgear innovation, including the entire evolution of MV switchgear technology to date. Premset switchgear is the result of this extensive knowledge and experience, representing the kind of leap forward only seen in switchgear technology about once every 20 years," adds Kruger.

For more information on Premset, visit www.schneider-electric.com/Premset. Contact Jacqui Gradwell, Schneider Electric, Tel 011 254-6400, jacqui.gradwell@schneider-electric.com

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the team

Editor
Clare van Zyrieten

Advertising
Kim Dare
Carrol Beattie
Irene Blythe

Design & layout
Helen Hartzenberg, Elizabeth Lotz, Marina van Biljon, Chantel van Niekerk and Jeanette van Wyk

Published by EE Publishers (Pty) Ltd
P O Box 458, Muldersdrift, 1747
Tel 011 543-7000, Fax 011 543-7025

Opening speech by AMEU president

Honorable Minister of Energy, Executive Mayor of Ekurhuleni, councillors, president of SAIEE, chairperson of PIESA, chairperson of the affiliates, past presidents of the AMEU and honorable members, foreign visitors, EXCO, members, colleagues, friends, ladies and gentlemen. It is my pleasure to welcome you to this 63rd AMEU Convention at the gateway to Africa and the City of Ekurhuleni. From reports I have received, this convention is going to be something special.

We again have a record number of registered delegates (650 to be exact), the most exhibition stands ever at an AMEU convention and a record number of foreign guests. This tells us that the AMEU remains a relevant association even in today's tough times.

"Smart" is of course the latest buzz word in the industry internationally and we thought it fit to bring you the first convention in South Africa to zoom into this topic and appropriately themed it "Solutions for a smart industry". I was fortunate to attend the IEEE's transmission and distribution conference in the USA which was dominated by smart grid and related topics. It was noted that first world countries had made major strides in converging to smart grids and that South Africa can draw on the lessons learned from them. On my way here I saw a huge poster at both Cape Town and Oliver Tambo airports that smarter grids can save 15% of peak energy usage.

Building on some of the initiatives that the immediate past president, Sy Gourrah, had started, I am proud to report that three of our five EXCO committees are now chaired by ladies and those ladies will chair sessions during this convention. We have also continued our collaboration with SALGA and are regularly requested by the Parliamentary Portfolio Committee on Energy to present on matters affecting the industry. Of late COGTA has also invited us to present our views on matters affecting local government. We have firmed up the Namibian branch and hope to establish branches in other neighbouring countries. We have proposed changes to our constitution, which you will vote upon today, that will bring it in line with modern day thinking. One of my last tasks was to respond to the NERSA consultation paper on IBT.

There remains major challenges for the industry:

- Electrification
- The skills crisis
- Lack of investment in infrastructure
- Infrastructure and energy theft
- A tight supply/demand equation
- Continuous delays in the introduction of bulk renewable generation
- Disparate tariff structures, etc.

I have come to the conclusion, and it is my view, that electricity distribution or engineering for that matter, cannot be run effectively and efficiently whilst it remains embedded in local government. My view is that engineering services should be operated by utilities, maybe even private ones, in order to get proper services to our communities. I think we should start with metro and district boundries and work our way down to the least amount of feasible entities.

Michael Rhode, outgoing AMEU president.

We are privileged to have both the honorable Minister of Energy and the Energy Regulator here today and I look forward to their addresses and want to immediately thank them for their time.

I also want to thank the:

- City of Ekurhuleni for hosting and contributing generously to the convention.
- President Elect, Hannes Roos, and his team for planning the convention.
- Team from Van der Walt, led by Marisa Jacobsunder the watchfull eye of Jean Venter, who coordinated all the arrangements.
- Affiliates under the leadership of Louis Steyn, for organising the exhibition, the sportsday, and sponsorship for various aspects of the convention.
- Presenters who spent hours preparing papers.

Lastly I want to thank you, the delegates, who took time out of your busy schedules to attend the convention. Let me encourage you to learn, absorb, contribute, network and enjoy.

Michael Rhode, president of the AMEU

Keynote address at the AMEU Convention 2012

I want to express my appreciation to the AMEU for inviting me to deliver the opening address at your 63th Convention. You would recall that last year, I had to apologise for not honouring my commitment to open your convention in Cape Town due to the fact that I had to accompany the Deputy President, HE Kgalema Motlanthe on an official visit to the Peoples Republic of China.

The good working relationship that has started between me and the AMEU, and the long-standing relationship that exists between my department and the AMEU is appreciated. The important role that the AMEU is playing, not only in keeping the lights on at a municipal level, but also as a professional association that is operating on different levels within the electricity distribution industry, is recognised and valued. This role ranges from fulfilling your technical responsibility to rendering not only assistance at a political and governance level within local government, but also to be a resource base for influencing national standards, policies and strategies. This is not, you would agree, an easy task given the ever changing environment, be it political, technical, as well as some of the structural challenges that are inherent within all spheres of government and the EDI environment?

One such new aspect that the electricity industry is globally implementing, and South Africa has to implement in a smart manner, is the issue of smart grids and smart technical and customer communication technologies. Hence, I am very excited to notice that your convention theme this year is "Solutions for a smart industry". This is very appropriate and timeous, and I will come back to this topic later in my short contribution.

We are all aware that the mandate of the Department of Energy is to create an environment which will secure a sustainable provision of energy for socio-economic development for the country and the continent.

Government, and the Department of Energy, in particular is focusing on various energy related aspects, but for the purpose of this gathering here today, I want to highlight the following matters:

- The provision of an enabling platform for other sectors to speed up economic growth and transformation, create decent jobs and sustainable livelihoods.
- Sustainable energy resource management and use.
- The unlocking of infrastructure investment through policy and regulatory framework.
- That we improve our efforts to meet the energy efficiency and renewable energy targets.
- Security of supply of electricity through the revamping and maintaining of the electricity infrastructure – specifically that of distribution and reticulation.
- We refine the integrated national electrification programme to eradicate the electrification backlog as part of our endeavour to achieve universal access.

It is impossible to consider the security of the supply situation without critically addressing the problems facing the electricity distribution network. It won't help the country if the new build programme ensures an adequate supply of electricity but it cannot effectively and efficiently be distributed to the end users.

Cabinet made a decision in December 2010 to discontinue the process of restructuring the electricity distribution industry through the establishment of the regional electricity distributors or REDs. Cabinet also approved the housing of the electricity distribution industry restructuring process within the Department of Energy.

This does not mean that the reasoning and the work done by the EDI Holdings is or was not applicable or relevant. The challenges in the EDI are still with us, as a matter of fact, in some cases it has even worsened during the last few months.

Dipuo Peters, minister of energy

The current challenges in the distribution sector, such as maintenance, refurbishment and strengthening backlog can be solved within the existing regulations and legislation, but to apply them more effectively; the focus will be shifting to implementation rather than a new structure to resolve these challenges.

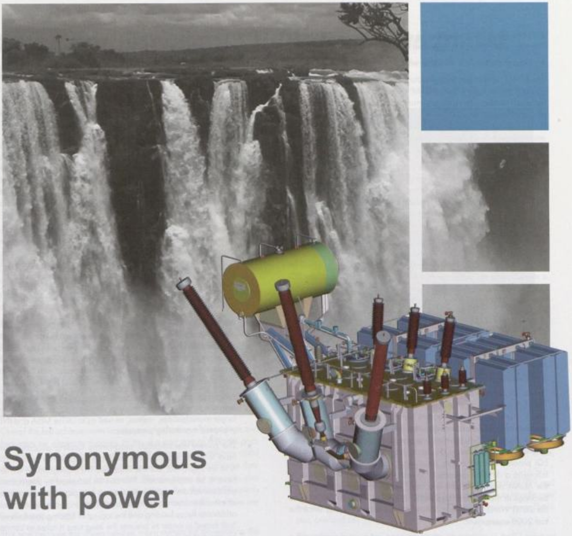
Current pockets of excellence within distributing utilities need to be shared with struggling utilities. Assistance from relevant municipalities, metros, Eskom, national and provincial departments such as COGTA through the MISA process, AMEU, SALGA, OSSA and other relevant institutions will be required in this process.

Also important are initiatives such as the Minister of COGTA's "Local government turn around strategy (so-called TAS programme)", the PICC (Presidential Infrastructure Coordinating Committee) initiatives under SIP 6, which is focusing on the maintenance backlogs and upgrades required in water, electricity and sanitation bulk infrastructure in the 23 least resourced district municipalities, in total 108 municipalities, covering 17-million people.

In parallel, DoE will implement the Approach to Distribution Asset Management or ADAM programme which forms part of SIP 10, to address the distribution industry infrastructure and resource challenges.

ADAM, you would know, is in essence a three pronged approach which:

- Addresses the infrastructure challenges, including the financial shortcomings.



- Manages these challenges by strict programme and support by means of project management practices.
- Addresses the skills shortage within the EDI.

The ADAM roll-out has been structured into different phases. The first phase is the so-called "mini-ADAM" phase, in which the roll-out will be tested at about ten different municipalities and two metros. This phase will also be used for DoE to set up the processes and systems to manage such a programme. For each municipality that will receive assistance, a project steering committee will be established to oversee the implementation of the refurbishment process.

A steering committee might be responsible for more than one municipality and will consist of various stakeholders, including AMEU. In this process, the DoE wants to tap into the technical resources of AMEU. We would also be interested in some of your retired AMEU staff to become part of this assistance group which DoE is planning to establish.

As confidence builds the methodology of implementating ADAM in the "mini ADAM" phase, more funding will be made available to roll out the second phase of the programme. The second phase will be a more holistic rollout of the ADAM programme to the broader EDI distributors, including Eskom regions. Currently, different financial models are being considered to address the financial challenges in the EDI.

I want to emphasise that the assistance as being envisaged through the ADAM process, will not mean that the current backlogs in the EDI will be funded in full or the EDI skills challenges will be resolved by national government. The management of the municipalities and metros has to take up some of the burden of this challenge.

Hence, all spheres of government will have to make a contribution. The ADAM process is not and will not become a hand-out programme, where municipalities will receive funding to solve a very serious problem. The EDI Holdings process has taught us that very many of our municipalities have not re-invested into their infrastructure as they were supposed to do, especially during the period that the EDI process was still active. As a result, the ADAM process will be following a different approach. In order to support the initiation of the ADAM program, there is a need for a fresh assessment of the backlogs in the EDI, because there have been major events such as the 2010 World Cup, which influenced the industry status since the last 2008 assessment.

In the next few months the DoE will conduct an assessment of the current backlog situation, to ensure government that the planning and modeling can be done by utilising the most up to date data regarding the EDI.

I will deal now with the electrification programme. The electrification programme is managed by INEP. The process is managed through applying some criteria and rules, which are debated, drafted and approved by the national electrification advisory committee (NEAC). AMEU is an active member of this committee, and the contribution of the association is appreciated.

Electrification is a cornerstone of social and economic upliftment, and has been proven to positively contribute to South Africa's development goals. Progress to electrify South Africa has so far been good, with more than 5,5-million connections made between 1994 and 2011, confirming South Africa's electrification leadership role in the sub-Saharan region and its positive development path compared to other emerging economies. Nevertheless, there are still 3,4-million households without electricity in 2012 of which about 2,2-million are in rural areas, and about 1,2-million in informal settlements in urbanised areas of the country. Considering the recent electrification rate of about 200 000 households annually, as well as limited funding allocations, inefficiencies in the electricity distribution industry, universal access to all unelectrified households would take about 20 years. In addition, more unelectrified households are being added each year, which adds to the pressure of delivery.

My department has developed a new implementation strategy to ensure that the rate of delivery will be improved by utilising the following measures:

- It is recognised that electrification can not only be defined as a grid connection, since it is in some cases just too expensive to build infrastructure for a few households in deep rural areas. It is suggested to implement more non-grid solar systems, but systems with a higher electricity capacity than what is installed currently (50 W systems vs 150 W systems), to address this challenge. Currently about 52 000 solar systems are in use by customers in rural areas (50 W systems), where grid connection is too expensive. This will not only release some electricity from the national grid and generators, but can also increase the electrification rate at which an electricity service can be delivered, since the non-grid roll-out is cheaper and quicker.
- The future roll-out of the electrification programme will have to be done in accordance with a national electrification master plan that will be developed through municipalities, IDP inputs and assistance of Eskom. It is foreseen that the first draft will be finalised in mid 2013. The respective electrification projects in the country will have to follow this plan. If such a holistic plan is not followed, it will not be possible to reach universal access in the country.
- We will improve the inefficiencies in the delivery of the electrification programme by managing Eskom and the municipalities more tightly. Some success has been obtained by managing the programme holistically; to manage or allow the respective entities to share the internal processes with INEP. In this regard inefficiencies have been identified and highlighted.
- Assistance will have to be given to struggling municipalities in delivering the INEP programme by utilising the capacity of Eskom, larger municipalities, metros, as well as to utilise MISA and INEP improved monitoring processes.
- The current electrification programme funding allocations will have to be increased, if the electricity programme delivery rate is to be improved, but the improved INEP programme will first have to be implemented. This can be achieved by international grants which are available for the non-grid programme, improved efficiencies which are already resulting in more connections, additional fiscus funding and the top-up of funding shortfalls with "soft loans" in order to prevent the long time it takes to connect houses due to slow delivery of important infrastructure projects.

Considering the above proposals with respect to an improved electrification implementation plan for the future, universal access to all exiting households and future households should be possible by 2025.

I want to request the AMEU to keep on participating in these processes and to make constructive contributions to the INEP programme, since you are the closest to the coal face of the industry through implementing these policies. I also want to make use of the opportunity to thank the AMEU for their positive contribution to the development of the new implementation strategy over the last four months.

It is important that the full effect that such technology can have on addressing challenges faced by the electricity distribution industry (EDI) such as the huge backlog in investment, infrastructure maintenance and strengthening, be harnessed. While trying to address these challenges, it is essential that the grid is modernised by deploying the latest technologies. This will lead to among others regulatory compliance, enhanced asset management, industry sustainability, service delivery and job creation.

The DoE in collaboration with SANEDI is involved in a project to establish the current state of the business and gap identification in standardisation of smart meters, stakeholder involvement and management, and the decision on suitable pilot sites for initial

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Incoming president's address at the AMEU Convention 2012

It is indeed an honour to have been elected president of the AMEU. An honour yes, but it also comes with some trepidation as I ventured on this road for the two years which I know will be exciting, rewarding and a most enriching experience. While this is indeed a feather in my own cap and a personal gratification, it would not have been possible without the support of the City of Ekurhuleni which has allowed me to fulfil this role. I would not have been able to tackle this demanding task without the support of my HOD, Mark Wilson, and colleagues of the Ekurhuleni Energy Department, it is greatly appreciated.

Since being nominated as President Elect at the technical convention in Cape Town in September 2011, I could already start feeling the pressure on what was still to come. I've had a year in which to realise what I am in for and, as you no doubt know, it is always easier to sit on the side line than being "it" in the hot seat! I thank you for the confidence you have shown in me and I am proud to be able to serve the association, the City of Ekurhuleni and our industry as president of the AMEU.

Allow me to remind you that it was our predecessors – who had the vision to establish our association way back in 1915 because they believed that it was necessary "to promote the interests of Municipal Electricity Undertakings".

They did this by developing and agreeing on technical standards for our industry, promoting the standardisation of regulations, by-laws and safety standards, the training of technical staff, and promotion of good management – to name but a few things.

One of the first achievements was the standardisation of the voltage and frequency for electricity supplies. In this day and age of national grids we easily forget that in the early days all member undertakings relied on their own local generating stations, and were free to choose their own supply voltages and frequencies. Did you know, for example, that during World War 2, and a year or two thereafter, the old VFP system (pre-Eskom era along the Witwatersrand) operated at 50, 5 cycles per second (Hz) not 50?

This was because the mines needed more pumps for de-watering the deep level shafts, and because the machinery was unobtainable because of the war they negotiated for the frequency to be raised to increase the pumping capacity! It worked...

We also need to be reminded that from early on our colleagues played leading roles in the work of the SABS and the various government departments involved in our industry. We still do, of course.

I am proud to have worked with some of those pioneers – people like Al Fortmann, Jules von Ahlften, Jan Loubser, Eugene Pretorius – all of whom have since passed on to a higher srvice. I have fond memories of people like Howard Whitehead, At van der Merwe and John Ehrich – all important pillars in our proud history who have retired from municipal service, but who still play active roles in the industry. And then, ladies and gentlemen, my favourite, and I am sure you will all agree with me, Max Clarke. After all these years he is still involved in the industry (AMEU and SAIEE and the like). Thank you Max, for all your inputs, they are much appreciated.

From my introduction to the industry in the late 1980s I have benefitted and grown from the collective wisdom of the association, and those early engineers. I have great appreciation for the colleagues who advised and supported me during my spell as secretary of the Highveld Branch in 1992, and my later progression to vice-chairman and then chairman of the branch in 1994. I recall well how some of these people used to sit in the Highveld branch meetings scrutinising my minutes of

Hannes Roos, incoming AMEU president.

the meetings, looking not only for spelling mistakes but also checking if the wording of my sentences made sense... as a youngster at that stage I was initially intimidated, but will never forget the support given to me, and the collective wisdom passed on to me.

I also recall my early membership of the executive council in1999 and the support received in the various jobs I was called on to handle over the years... and now this great honour of being your president. Thank you, one and all.

There have been many changes to the association in its 97 years of existence. These have not only been to its constitution and membership, but also to the technical, social and political environment in which it operates. With each change we have built on the rock-solid foundations laid by those who have gone before – some of whom I have mentioned earlier. We have successively met each challenge, and have come through stronger than ever – always ready and able to guide the industry and the policy makers on how best to meet our primary objective of serving our customers with the best electricity supply possible.

One of the significant changes in recent years has been the appointment of Past President Peter Fowles in 2004 as a special adviser to assist the Executive Council in the increasing number of meetings, discussions and negotiations – many both demanding and complicated – with government and parastatal organisations that are now the order of the day.

This is now a full-time appointment and I express my appreciation to Peter for the way he has been able to relieve the workload on our office bearers, and provide an indelible AMEU imprint on the regulatory and policy issues, and the related organisations that seem to be multiplying each year.

And what of the future?

During my term of office I will try to extend our membership to South African municipalities who are not yet members of the association and, from my experience as a board member of PIESA, I hope to broaden the membership even further by persuading some of our African neighbours to join us. When I see how Namibian utilities are responding to our recently formed branch, I believe we can persuade other neighbours to join us and benefit in a similar way.

My first official task is to present the outgoing President Michael Rhode with a certificate in recognition of his outstanding service during his term as president. And also want to make use of this opportunity to present the Past President Sy Gourrah with a certificate in recognition of her outstanding service during her term as president. And I am so sure that we all still remember that Sy was our first female president of the AMEU.

They both showed a keen interest in promoting the activities of the AMEU through their dedicated participation in the different responsibilities as president, and as members of the executive council and committees of the AMEU. The feedback received from different AMEU branches and affiliate activities, highlight that they were there and very much involved. They set a high standard of commitment and loyalty, and that is part of the pressure I mentioned earlier that I am experiencing. I trust that I can continue to build on what they achieved to the advantage of the AMEU, and the industry at large.

On behalf of our colleagues here today, I thank them for a job well done.

It gives me pleasure to present them with these certificates of grateful recognition for the dignified and inspiring manner in which they have fulfilled this high office, and in recognition of their unselfish efforts in promoting and furthering the objectives of the association.

Hannes Roos, incoming president of the AMEU

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program implementation. Estimated budgets for the respective three years, as well as timelines are also indicated in these discussions.

The results from this exercise will assist the DoE to guide the electricity industry in defining amongst others, the required standards, technology choices and the deployment of appropriate technology. I want to urge the AMEU and the conference attendees to support this initiative of the DoE and SANEDI, to make positive contributions and to keep engaging with us in shaping this programme.

I want to end off by urging the AMEU to keep on fulfilling the positive contribution the association has made over years with regard to the EDI and the electricity industry in general. In building these professional and complimentary roles, you must not act like an opposition party that is only complaining about what is wrong, but rather find common solutions for the challenges in the electricity industry.

I think that the time has come to establish a more formal relationship between DoE and AMEU. This needs to be further investigated to ensure that where DoE and others in the industry lack certain skills and industry experience, we must be able to draw on and benefit from professional entities like the AMEU for future engagements.

I want to wish you and the association a productive and blessed 63rd Annual Convention, and we look forward to the outcome of this gathering, as well as your ongoing engagement with us.

Dipuo Peters, minister of energy

Honorary membership awards

Deon Louw, on behalf of Jorge Pereira, Paul Johnson, Ferdinand Diener, Michael Rhode, Louis Steyn, Roy Wienand and Stephen Delport.

Jorge Pereira

Jorge Pereira has been an affiliate member of the AMEU since 1990 representing the former ASEA Electric, ABB Power Transformers and, until his retirement earlier this year, PowerTech Transformers. Mr Chairman I have personally had the honour to work with Jorge since 1987 when we took part in an electrification project at Khayalitsha. Jorge has attended every Good Hope Branch meeting, save for two meetings, over the past 22 years, and has been instrumental in assisting to make the Good Hope Branch meetings successful over all these years through his company's generous sponsorship of the local meetings and functions. Jorge has been an institution at the Good Hope Branch meetings. The Good Hope Branch takes great pleasure in nominating Jorge to be honoured by bestowing on him an honorary membership of the AMEU.

Paul Johnson

The AMEU bestows honorary membership onto individuals, who the association wishes to honour for outstanding service to the electricity supply industry. Paul Johnson is a professional engineer and a fellow of the SAIEE. He has served with Eskom for 32 years and is currently in a senior position at the SABS. For the past 20 years Paul has been a key role-player in standardisation processes on an industry level, linking Eskom's standardisation processes through the ESLC with the broader industry in South Africa and further through PIESA and AFSEC into Africa, including roles with the IEC and its regional committees, IERE and UPDEA. He served as chairman of PIESA for some years, is the current secretary general of AFSEC and was a past chairman of the SAIEE Power Section. He also served, for many years, as a director of the Standard Transfer Specification Association, an organisation which is now reaching out as a global player in its particular field. Paul lectures regularly on standardisation and has published a number of papers on the subject. Paul is a familiar attendee and participant at AMEU events and conventions. We propose to honour Paul for his pivotal role over so many years in furthering standardisation in our industry.

Ferdinand Diener

The AMEU bestows honorary membership onto individuals, who the association wishes to honour for outstanding service to the electricity supply industry. Ferdinand Diener is a professional engineer who headed up the electricity department of the City of Windhoek for the past 14 years until his retirement in early 2012. Previously, Ferdinand served at Nampower and Windhoek in various capacities. Ferdinand was instrumental in maintaining links between the Namibian members and the South African members for many years, including doing the arrangements and groundwork for various visits by the executive council and other South African delegations to Namibia. We propose to honour Ferdinand for his pivotal role in establishing the Namibian branch of the AMEU and for his help in maintaining relationships across the border.

Michael Rhode

Michael J Rhode, who is a past Chairman of the Good Hope Branch, member of the Executive Council of the AMEU and current/immediate past president, is nominated for honorary membership to honour him for his dedication and service to the association and his valuable input given over many years to further the aims of the AMEU. Michael is the president elect of the Southern African Revenue Protection Association and board member of the Power Institute of Eastern and Southern Africa (PIESA). He has served as head of electrical services in four municipalites and has extensive understanding and knowledge of the South African transmission and distribution grid. He is currently the head of electricity in the second largest municipality in the Western Cape, namely Drakenstein Municipality. He obtained his electrical engineering degree at the Stellenbosch University and is a registered Certified Energy Manager and also holds a Government Certificate of Competence. The Cape of Good Hope Branch is extremely honoured to nominate Michael as an honorary member of the Association of Municipal Electricity Utilities.

Louis Steyn

It is indeed an honour and a privilege for me to propose to this convention that honorary membership of this association be bestowed on another special man in the history of our organisation. It is a pleasure to introduce to you the person that I am speaking about – Louis Steyn. I have known Louis since I started attending the AMEU in 2001 and more recently when Louis became the chairperson of the Affiliates. He joined the AMEU during 1990. During his 20 year term at the Powertech Group, he mainly worked at Aberdare Cables as a sales manager and product manager, of the municipal and the mining sector until 2010. He offered advice to the electrical industry or institutions whose decisions and policies might affect the electrical industry. He played a major role in the design and introduction of a special shaft cable in conjunction with the cable factory and the engineers from Anglo Gold as well as a five core low voltage cable to the mining industry. He promoted the spirit of co-operation and shared responsibilities amongst other professionals and providers. In 2007, he was elected by the AMEU Affiliates members to the committee and was elected as chairman of the Affiliates Committee during 2009. He joined ADC Energy as their national sales manager in 2010 for 18 months, supplying the industry with various technologies in switchgear, transformers and electrical cable. Recently he started his own consulting company (WDI Consultants) and is involved in the electrical industry, specialising in electrical cable, transformers, switchgear and metering. Our constitution defines an honorary member as "a person who has distinguished himself and whom the association desires to honour for outstanding services". Mr President, I submit to you that Louis Steyn be conferred with honorary membership of the AMEU.

Roy Wienand

It is an honour and a privilege for me to propose to this convention that honorary membership of the sssociation be bestowed on another very special man in the history of our organisation. Roy Wienand was born in 1960 in Dundee, KwaZulu Natal, and educated at Saint Andrews College, Grahamstown, and the University of Natal in Durban from where he graduated with a BSc Electrical Engineering. He subsequently also graduated with an MBA from the University of KwaZulu Natal. He is registered with the ECSA as a PrEng and is also a senior member of the South African Institute of Electrical Engineers. Roy received a bursary from the erstwhile Durban City Council (now eThekwini Metro) to study engineering and has worked for its electricity department for 28 years. He has experience in planning, construction and maintenance of the HV, MV and LV networks and is currently their director of operations. In recent years he has led the council's green energy special projects and was intimately involved with the very successful eThekwini landfill gas project on which he has presented a number of papers, including at our 2007 Convention. It is Roy's role with the AMEU that I would like to highlight. Roy has taken a very active part in the proceedings of the KwaZulu Natal Branch of the association for as long as I can remember where he has served periods in the positions as vice chairman and chairman. Apart from his loyalty to his branch, Roy has played an extremely active and valuable part in the AMEU's activities at the national level. Examination of the AMEU list of representatives on various boards, associations, committees and workgroups will give some indication of his involvement to the benefits of our industry. It is too long to detail here but suffice to note that he has served on numerous committees of the AMEU, the DME (now DoE), Eskom and the EIUG, EDI Holdings, NERSA and PIESA. He is the immediate the past chairman of the ESLC, responsible for the NRS specifications process, a position he held for 12 years and was also the long standing chairman of the AMEU tariffs committee, which he relinquished in November 2011 when the executive made a decision to appoint new chairpersons to all of the standing committees. I have known Roy for many years and his knowledge, loyalty, professionalism and humility are characteristics that I admire tremendously. Attending a meeting chaired by Roy is a pleasure. His dedication and passion for the AMEU and the municipal industry are strongly evident whenever he participates in meetings and functions which together with his wisdom, knowledge and experience have assisted in raising the profile of our organisation. I particularly admire his constant calls for reason and fairness in all matters. Our industry is privileged to have a person of the calibre of Roy in our ranks. It is with regret that I note his decision to step down from some of his numerous national activities (like the ESLC aand PIESA) to concentrate on his demanding responsibilities with the eThekwini Metro.Our constitution defines an "honorary member" as "a person who has distinguished himself and whom the association desires to honour for outstanding services". Mr. President, I submit that Roy Wienand has more than met these requirements and I humbly request that he be conferred with honorary membership of the AMEU.

Merit award

Stephen Delport

Many members of the AMEU over the years have gone the extra mile in serving the association and the industry in giving their time and expertise to a large number of association and technical workgroups, such as the NRS workgroups, convened to address common industry issues. One such member is Stephen Delport. Stephen first qualified as an electrician and as an installation electrician. He received his National Diploma in 1986 whereafter he passed the Government Certificate of Competency examinations and qualified as a Certificated Electrical Engineer in 1987. In all, Stephen has had more than 33 years of extensive experience of electrical distribution networks at voltages from 400/230 V to 132 kV. Stephen has been a staunch supporter of the AMEU Highveld Branch, serving as its secretary from 2002 to 2004 and as its chairman for the 2005 to 2006 period. In 2006, he was a finalist and received an award in recognition of service excellence in the category "Most innovative idea" for power quality monitoring implementation within Ekurhuleni. During this period he has been active on a number of industry workgroups such as the EDI Holdings wires committee, the PIESA electrification and power systems analysis workgroups as well as several NRS Workgroups. He is currently the chairman of NRS 048 quality of supply workgroup. It is Stephen's role with the AMEU Tariff Committee that I would like to make special mention. Stephen is a very knowledgeable and active member of this committee and when it was decided in 2010 to discontinue the annual AMEU tariff survey, the results of which no longer provided a reasonable comparison of the average cost of the electricity for typical customers in the sampled distributors. We believed that the survey was an important service to other distributors and interested members of the public and it was Stephen who took on the task of developing a model that could be used for the comparison of the cost of electricity for a particular customer profile in different tariff areas. He completed this project earlier this year after many, many hours of work. The AMEU Executive Committee is very proud of this extremely useful tool that is a living example of our objective to provide an advisory service to our members and customers. The effort expended by Stephen on this model has gone above and beyond the call of duty and the AMEU executive wishes to extend this Meritorious Service Award to Stephen.

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Hosting the ACE 2013 is a spin off from the 2010 Soccer World Cup, when the Ekurhuleni 2010 office submitted a bid to Global Insight to host the annual conference. In early 2011 Ekurhuleni was announced as the host for ACE 2013.

A new strategic approach to airport planning and associated commercial development is gaining momentum around the world. This is the airport city and aerotropolis model. It consists of an airport centered commercial core (the airport city) and outlying corridors and clusters of aviation-linked businesses that make up the greater aerotropolis.

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Hannes Roos, incoming AMEU president.

Clr. Aubrey Nxumalo, City of Ekurhuleni.

Phindile Nzimande, CEO NERSA.

AMEU Affiliates past chairman, Louis Steyn.

Minister of energy, Dipuo Peters and Jean Venter, AMEU general secretary.

AMEU past president, Sy Gourrah.

AMEU president Michael Rhode, with incoming AMEU president, Hannes Roos.

Peter Fowles, AMEU.

Sicelo Xulu, AMEU president elect.

Dr. Clinton Carter-Brown receiving the Cigré best paper award.

New AMEU Affiliates committee with the past chairman, Louis Steyn.

Kobus van den Berg receiving the best paper award.

Smart grid evolution through microgrid aggregation in Africa

by Dr. Wajdi Ahmad and Dr. Lana El Chaar, GE Energy

Smart grid vision integrates a whole host of software and hardware solutions with the aim of modernising the power grid across its entire value chain. This comprises solutions that aim to optimise the process of energy delivery and utilisation, starting at the high voltage transmission grid, going through the medium voltage distribution grid, and all the way to low voltage consumption.

This vision requires close collaboration and commitment from a variety of stakeholders, comprising policy makers, utilities, industry, academics, and consumers. Smart grid means different things to different people; therefore, it has to be customised to address the particular drivers and pain points of the utility, and be executed in a phased approach. Furthermore, it is extremely important to have solutions that are interoperable and standards-based in order to prevent monopolies and technology obsolescence.

Central to the smart grid vision is the aim to increase energy efficiency and enhance power system reliability. Energy efficiency relates to power grid losses, whereas reliability is closely tied to outages. The traditional power grid topology is based on one way power flow from a centralised power plant through a massive grid of various voltage levels to the end users. One way to reduce technical losses incurred through the energy delivery process is to reduce the power transmission distance by utilising distributed energy resources (DER) placed close to the loads. The use of DERs, e.g. diesel, wind, biomass, rooftop solar, etc. can increase power availability and enhance reliability. The integration of DERs obviously changes the traditional topology of the power grid and opens the door for two-way power flow, whereby the consumers can become producers and feed power to the grid, hence the notion of "prosumers". However, some DERs may pose a big challenge for integration into the power grid; for example, solar and wind power generation are naturally intermittent, causing the DER generation output to be unpredictable and fluctuant; hence putting the system's safety at higher risk [1]. Therefore, incorporation of big chunks of such resources requires advanced solutions to facilitate such integration. This change in power grid topology could not have been possible without the sophisticated smart grid solutions such as microgrid.

What is a microgrid?

A microgrid (MG) is a miniature representation of the bigger, or macrogrid. It comprises local power generation, local load, and an advanced control system. It may be connected to the larger grid through a connection bus, or may be completely isolated and operate in an "island" mode. Furthermore, it may include community energy storage (CES) to store excess energy from renewable resources such as wind and solar, which will compensate for power loss caused by intermittency. Such approach will not only solve the interconnection of large DER with large power system but it can also benefit the customer as users can be supplied power even during outages [1, 2 ,3]. Moreover, storage devices provide the amount of power required to balance the system following disturbances and/or significant load changes. Fig. 1 shows a typical configuration of a grid-connected microgrid system.

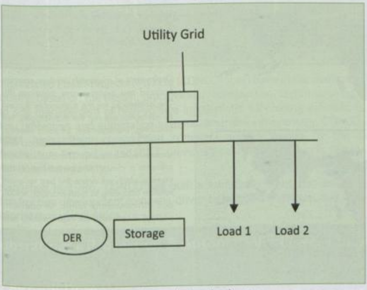


Fig. 1: Grid-connected microgrid configuration.

Whether the MG is grid-connected or islanded, an advanced control system is needed to take the appropriate actions for load and generation management. For example, in the case where the MG is connected to the larger grid and the tie connection is lost, the control system will take appropriate actions that might include load/generation shedding to maintain the load-generation balance in the islanded area.

The control and management required for MG operation is different than traditional power system control, as MG is modular and may contain different generation type equipment with different characteristics and dynamics, containing short/long term energy storage components to stabilise the system. Hence, there are two main types of MG control: advanced unit-level control and system level integration control [1]. The unit grade controller which includes DER and load controllers, execute system level controller commands in addition to local information allowing decisions to be made with respect to voltage or frequency control. The MG system level control, also called MG central controller, where orders are given according to market information for dispatching purposes as well as making system's decisions based on information interactions among controllers.

The main objectives of using microgrids are to facilitate integration of distributed renewable energy resources and to provide high quality and reliable energy supply to critical loads. Microgrids benefit the overall power utility by deferring major investments in power generation plants and transmission and distribution infrastructure. They also enhance reliability as a result of their ability to respond quickly to maintain the generation-load balance during disturbances. Microgrids have four operating stages, in all of which reliability must be ensured:

- Transient stage of going to grid-connected mode.
- Steady stage of grid connected mode.
- Transient stage of going to island mode.
- Steady stage of island mode [1].

The stage of island-mode operation is affected by power quality, capacity of energy storage device, communication networks and types of DER. The management strategy in this mode of operation depends mainly on the local climatic conditions, load demands, fuel consumptions and power quality.

Microgrids and rural electrification for sub-Saharan Africa (SSA)

Electricity is undoubtedly crucial to human development, and plays a vital role in facilitating essential activities for end users. The rate of electrification of a certain community can be used an accurate measure of its level of energy poverty [4]. Many countries do not have the capacity to build large centralised generation plants or transmission infrastructure. There are now an estimated 1,5-billion people without electricity in developing countries, and 85% of them live in rural areas [5]. In 2009, sub-Saharan Africa (SSA) had about 585-million people without access to electricity, with the urban electrification rate standing at 59,9% and a rural electrification rate of 14,2% where most of the available supply is unreliable [5]. Fig. 2 shows a global picture of the numbers (in millions) and the percentages of people without electricity.

The study conducted by the World Energy Council (WEC) in 2004 highlights the fact that Africa could be energy self-sufficient due to the various ample resources. However, this is not possible as these resources are at wide disparities in access to electricity [6].

In many cases, grid extension is often highly costly and not feasible in isolated rural areas, or is unlikely to be accomplished within the medium term in many areas. This is particularly true for SSA, where the vast land area and terrain nature pose big challenges for grid extension. In such situations, microgrid systems can be installed locally in rural areas to provide capacity for both domestic appliances and local businesses. Microgrids have the potential to become the most powerful technological approach for accelerated rural electrification. It is quite possible to incorporate isolated MG to meet the demand of rural communities without wearing heavy financial resources [7]. Microgrids can be used as basic building blocks for future system expansion.

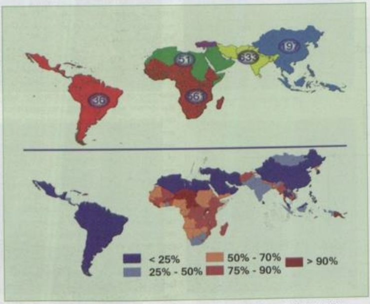


Fig 2: Number (millions) and % of people without electricity, 2008. Source: WHO & UNDP.

The combination of renewable energy sources with a genset has proven to be the least-cost solution for rural communities, as the benefits and advantages of each technology complement each other [8]. In the case of SSA where transportation of diesel for power generation in rural areas can be very costly, renewable resources can be used as the primary source of power generation. This primarily comprises solar and hydro, while diesel can be used for back-up generation. Hence, an additional benefit is realised through mitigation of carbon emissions, thus contributing to sustainable development and helping in the battle of fighting climate change. Furthermore, the MG concept can influence the market and level of competition for prime sources of energy. It helps reduce dependency on imported fuel sources and support in regulating prime fuel market competition.

The proliferation of these individually controlled small microgrids paves the way for eventually aggregating them into an integrated and interconnected smart grid with improved efficiency, enhanced reliability, and environment protection through renewable integration. Multiple distributed microgrid controllers could eventually be integrated with a master distribution management system (DMS), using an appropriate communications infrastructure, most likely IP-based, thus forming an important element of the end-to-end smart grid vision for the utility.

Microgrid deployment challenges

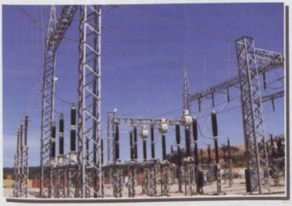
Although MG presence sounds practical and provides a feasible solution to increasing energy demand, utilities are cautious in integrating dispersed generating units to their systems [7, 9]. Clear and consistent policies are required to support this initiative. Other challenges can be categorised into non-technical and technical.

Non-technical challenges

Deployment of microgrids involves complex financial and organisational questions [8]. The bottlenecks for the sustainable success of microgrids are not the technologies, but financing, management, business models, maintenance, sustainable operations, and socioeconomic conditions. Each community presents a cluster of characteristics and interests which will define the best technical solution according to local financial, social, and environmental terms. In addition, pricing, incentives, risk responsibility and interconnection standards and regulatory control must also be addressed

Technical challenges

Urgent concerns and needs must be tackled such as safety, islanding, restoration from



scheduled and unscheduled outages, power quality liability, capacity and reserve management [7, 9]. Additionally, other challenges including interconnection requirements, level of penetration and power exchange are imposed by utilities [1, 10 – 13].

Conclusion

Despite the various challenges facing microgrids, the merits of such systems are definitely worth their penetration, especially in rural/remote areas. It will ultimately change how electricity is generated and its impact on human development. It will also enhance the efficiency of the use of local resources, help meet the demand regardless of geographic location, and reduce the impact on the environment. However, some measures need to be addressed by all stakeholders involved in the energy sector to facilitate a safe and reliable MG integration. MG systems form a viable solution for rural and remote electrification in general and for SSA in particular, and can form the basic building blocks for a future smart grid evolution.

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Contact Dr. Wajdi Ahmad,
GE Digital Energy,
wajdi.ahmad@ge.com

Innovative approach to an ICT infrastructure supporting smart grids and smart metering

by Paul Renshall, Mott MacDonald

Power utilities across the world have recognised that a key enabler for the successful implementation of their smart grid and smart metering projects is gaining a higher level of intelligence and information from the power network, something which can only be achieved through the massive growth in the use of ICT systems and services.

The most flexible platform for the delivery of such services (as well as the existing requirements for operational telephony and general business communications), is undoubtedly a fibre optic based core network. Deploying fibre deeper into the network and closer to the customer has many advantages. However, adopting such a strategy comes with a significant price tag; for many regional and national utilities the necessary capital investment and subsequent operational costs of creating this ICT environment are huge and any business cases to support it are at best challenging and at worst non-viable. This situation can be exacerbated for utilities with smaller geographic footprints where economies of scale do not contribute positively to their commercial models.

This paper outlines an innovative approach that was considered in a project conducted by Mott MacDonald in 2008, where we designed a solution to create a single national fibre network specifically for the power utility industry based upon existing utility owned fibre. Although the solution was not implemented in this form, the initial planning exercise in association with the level of utility company engagement and cooperation that was achieved does provide insight into one way in which utilities could potentially achieve mutual benefit through a more collaborative approach to a common issue. In a territory such as South Africa it may well merit further investigation.

Background

Historically, many utilities have built their own in-house operational telecommunications (OT) networks and created extensive operation and maintenance support teams to manage them. This behaviour has been driven by a number of factors:

- Prior to the creation of competing fixed telecom network operators, the utility had little choice because incumbent, government owned telecom authorities would not invest to meet the needs of utility companies.
- Utility companies are by the nature of their business operation highly risk averse, and by keeping services in-house they can control the reliability, availability and dependability of the communications services that support the critical national infrastructure (CNI). This view is sometimes articulated when one discusses the issue of securing managed or outsourced services with utility companies; there is often common feedback that such an approach is difficult to adopt as "only the power industry really understands its needs".
- Some of the telecommunications services required by the utilities have to maintain very demanding performance attributes and characteristics (particularly for tele-protection services). The public telecommunications operators (PTOs) do not always provide such services, or such stringent service level agreements (SLAs) required for these services within their standard product portfolio. As such, utilities are then offered "bespoke" services by the PTO, which in many cases are more expensive than self provision.
- Due to concerns over national security, there is a growing view that transferring service delivery risk to third party service providers, regardless of the SLAs, contractual arrangements or punitive measures agreed between parties is inappropriate when operating and managing CNI.
- A power utility is under external pressure from regulators and legislators to drive improvements in performance, safety and ultimately value for money for consumers. By building, operating and maintaining their own in-house networks, utilities provide a level of commercial, contractual and technical stability that underpins their business operation. For example, any new technology implementations and upgrades can be based upon the utilities operational needs in a controlled, timely and budgeted manner, whereas a PTO may demand the upgrade or change to a technology platform used by the utility to suit its own business strategy, regardless on the impact to the utility.

For many utilities building, operating and maintaining in-house OT networks is an important element in supporting their ongoing corporate responsibility and accountability. This is also true for the multi-national utilities. In 2011, Mott MacDonald conducted an operational telecommunications benchmark study which compared a group of utilities from the USA, Europe, Africa and the Middle East. It was found that utilities which have a more global footprint (i.e. those with operations in more than one country) operate in a similar way to any global enterprise. Core business functions are centralised across the group, such as finance, human resources, purchasing and even IT and corporate communications. However, OT is in general delivered locally through in-house networks managed by in-house teams.

The challenges of in-house service delivery

Building, operating and maintaining an in-house OT network is not without its challenges and complications. This paper does not include a definitive list of these challenges but it does touch on a few key areas.

Firstly, it is expensive to build and maintain a dedicated network, and unlike a PTO there is a limited customer base to spread the cost with no immediate or significant revenue stream to recover the capital expense. Additionally, even budgeting for relatively small upgrades or network extensions can become more complex due to the way in which the local regulatory authority views how the costs are dealt with.

Secondly, utilities adopt a slower rate of communications technology change than PTOs. One may expect this to be advantageous to utilities, as once a technology is deployed it will remain "fit-for-purpose" for perhaps 20+ years. However, in reality the technology market (dominated by PTOs) is driven by innovation and development, leaving utilities with ageing and in some cases unsupportable infrastructure. The issue is compounded by the complexities associated with the deployment and particularly the interfacing of new communications devices with the existing power engineering assets. Arranging network outages (both communications network and power network) to support these implementations is disruptive to the business operation and can take years to complete.

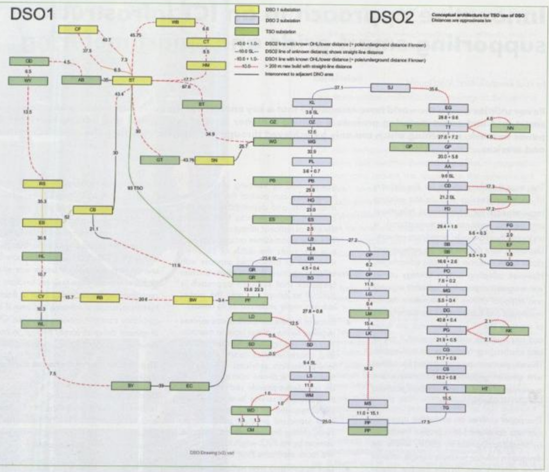

Fig. 1: Example concept design.

This results in utilities finding it hard to integrate new technology easily. As a consequence, this has created a "mesh of technologies" in many utilities, where network requirements have developed organically and new networks have been overlaid on older networks.

An additional challenge concerns the resource pool. Utilities worldwide are affected by an ageing workforce and diminishing skills base. It is relatively easy to recruit technicians and graduate engineers, however once the utility has invested the time and money in training and up-skilling these employees, staff retention can become a problem with more financially lucrative roles available outside the industry. Again, this is particularly true in the ICT environment were graduate recruits are likely to be less incentivised to work on what they perceive as legacy networks (TDM based technology), when the whole communications market is focussed on IP.

Telecommunications services are an important enabler for the safe and efficient operation of a utility (and without doubt their importance in performing this function will grow within the context of smart grid and smart metering) these services do not constitute "core business" to a power utility. As a consequence, there will always be pressure from the business to drive down cost and maximise efficiency of the telecommunications department – especially in an unbundled and competitive environment. This invariably means reduced investment in equipment and resources.

Many utilities then are faced with a dilemma. How do they find a solution to telecommunications service delivery that:

- Meets the demanding performance standards of OT.
- Supports the security requirements for CNI.
- Is scalable to support growth and capacity cost effectively.
- And can embrace new technology with the scale to make it cost effective?

The co-operative op-tel network

One possible answer may be to create a co-operative OT network, a ubiquitous fibre based communications platform that would be owned and operated by a group of utility companies. The cooperative network would be designed and built to deliver dedicated OT and B2B services to the industry, with the option to generate additional revenue through leasing spare capacity and services to the general market place. The platform could be used to support multi-disciplinary utilities (electricity, gas, water etc.) layered across the end-to-end value chain (generation, transmission, distribution and supply). Ultimately the platform could provide the basis for an integrated smart grid in its widest context, driving efficiencies and performance not just within each utility (today's smart grid focus) but in a truly customer centric manner linking traditional, renewable, bulk and distributed generation, storage, transmission, distribution, supply and the consumer.


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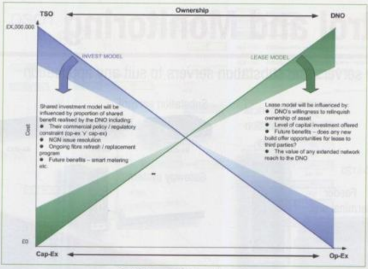

Fig. 2: Commercial framework options.

In 2008, Mott MacDonald was engaged by a client to develop such a scheme. While the project did not come to fruition in this form, the experience provides a valuable insight into what could be achieved, identifying some of the key activities and challenges involved in creating such a scheme, including assessing the overall scheme viability, design concept and architecture, the commercial framework options, the operating environment (including necessary service level agreements) and potential operational models. A brief outline of the case study is documented here to provide context.

Case study

A national transmission system operator (TSO) was considering its OT strategy for the next 15 to 20 years. As part of that strategy, there were some key drivers for change which it wished to consider:

- An urgent requirement to replace the ageing telecommunications assets and platforms, some of which were unsupported by the vendor community due to their age.
- An urgent requirement to upgrade and in some areas replace the ageing fibre infrastructure.
- The impact of the migration from TDM to IP services (considering both the effect of implementing and the effect of not implementing IP services for OT).
- Reviewing the likely future requirements for smart grid and smart metering and how these new services could be accommodated into their network.
- The sourcing strategy for the OT services – should they build an in-house solution or outsource the network to a PTO.

A fundamental decision taken by the TSO was that regardless of both the current and future services it required, the most flexible platform for delivering them was over a fibre based infrastructure. The immediate challenge therefore was how to implement a "refreshed" national fibre network with the minimum disruption to their existing operation.

The vision proposed by Mott MacDonald was to create a national fibre network through a combination of TSO and DSO fibre. The fibre network would be designed on a core and access network basis. The core network would be primarily formed from existing TSO fibre, and the access networks created primarily from existing DSO fibre. The scheme leveraged the fact that the DSO primary substations were located adjacent to the TSO substations. Additional fibre would be installed (either underground or OPGW or fibre wrap on the DSO network) to support the closure of rings for enhanced network resilience on both the core and access layers.

Challenges to implementation

Without doubt the most difficult challenge is opening the initial discussion and generating the interest between the various utilities. Lessons learned from the case study showed that from the outset it was important that discussions were led by a "neutral" party. This ranged from the initial presentation of the concept to each interested utility, through to the later design stages. This provided all parties concerned with a "level playing field" and was a way of successfully managing the competing interests that surfaced during discussions. By establishing this "neutral" buffer between the various utilities, concerns over confidentiality and commercial sensitivities can be more simply addressed. The process also illustrated that not every utility had to be interested or convinced from day one. Within the geography considered within the case study there was a national TSO and fourteen DSOs. Four of the DSOs were initially ambivalent about the scheme. However, as the momentum built they decided to actively participate in discussions.

In such a scheme, it has to be recognised that not all utilities will be equal participants, either in how much fibre they contribute, or in the services that they lease back. However, the platform has to be capable of delivering compatibility between all participants. The starting point for this is to recognise that the initial platform will support multiple technologies and solutions for multiple OT services and such solutions are readily available in the market today. Linked to this is ensuring that there is a fair and equitable commercial arrangement put in place which benefits all concerned parties.

Assessing the overall scheme viability

Creating a co-operative network can have a large impact on time and resources. It is therefore important to be able to assess the overall validity of the scheme quickly so that a decision can be made on whether to proceed or not. This can be achieved through some initial preliminary design activity which in essence will identify whether there are indeed enough assets to share (i.e. fibre, spare capacity etc.), what future rollout and refurbishment plans each utility has (in the case study, roll-out and refurbishment of OPGW plans for a three year period were considered) and the scale (and hence estimated cost) of any new build required to support the scheme. An example of such a design is provided in Fig. 1.

Design concept and architecture

As described earlier, the core design concept is to create a fibre network based upon a highly resilient core network connected to regional or local access rings. The core network is mainly provisioned through the TSO fibre and the access rings provided by the DSO companies' fibre. The interface point between the core and access layers in essence relies upon the proximity of the DSO primary substations to the TSO substations providing an effective point of present.

For the TSO, the design benefits can include identification of alternative routes between TSO substations (using routes created through the DSO networks) thereby providing either greater resilience, or creating alternative routes for maintenance/fibre replacement works, or providing future network extensions more cost effectively. Although in most cases these routes will not be the most direct (shortest) path between TSO substations, they are often more than suitable for telecommunications services.

For the DSOs the design benefits can be more significant. Firstly, there is likely to be much less fibre installed within a DSO region. Where fibre does exist, it may only be connectivity between small groups of primary substations. Often these clusters of fibre network are islanded from each other, and consequently across the DSO region not all the primary substations are connected to a single network. Through careful use of available TSO fibre and much reduced new build fibre, these clusters can often be connected creating a more resilient DSO network. Furthermore, (based upon suitable TSO fibre routes for access) it can be possible to extend fibre deeper into the DSO network. Within the case study, we also identified areas where adjacent DSOs benefitted from interconnecting and sharing fibre along the geographic boundaries.

The commercial framework options

The key commercial benefit to the op-operative network is cost sharing. The increased customer base (multi-utility), and theoretically the reduced length of fibre routing across the network reduces unit support costs through economies of scale. There are two key areas of shared cost. Firstly the shared cap-ex for infrastructure costs, which could be for new build or investment into the scheme by providing spare fibre capacity. Secondly the shared service management or lease costs (op-ex) from leasing capacity from the scheme. There are many options available for cost sharing and these will depend on the specific circumstances of the co-operative network that is achieved (see Fig. 2). Of course, one option of the model is to create a new utility telecommunications business, created as a joint venture between all the utilities, to build operate and maintain the network.

Operating environment

In addition to the asset sharing required to create the physical co-operative network, a suitable operational and maintenance environment has to be created. Again, many options exist and these will be determined by the specific solution created, however sharing of technical resources between utilities may prove beneficial. Issues to be addressed in creating such an environment are operating standards acceptable to all utilities, and importantly service level agreements between utilities (particularly in the event of incidents, faults and outages). As identified within the commercial framework options, some of these issues may be more easily addressed if a utility telecommunications organisation is created to support the co-operative network. Transferring technical staff from the utility to the new organisation focussed on telecommunications may be an attractive option to the utilities companies and staff alike.

Benefits of the co-operative scheme

The primary benefit of the scheme is the creation of a purpose built, bespoke network that caters specifically for utility requirements with the cost for the build, operation and maintenance shared proportionately across the utilities that utilise the network. The performance, topology and capability of the co-operative network perfectly reflects utility requirements, offering a fibre based flexible platform supported by other technologies within the DSO partners for delivering today's telecommunications services and indeed a basis for next generation communications services including supporting smart metering and smart grid. Additionally, the co-operative model has all the advantages of an in-house solution, but is in effect an "in-community" solution. This addresses concerns over security and risk associated with CNI and should be attractive to legislators and regulators alike. From a resource perspective, in the case of major faults there is potentially access to a wider resource pool from across multiple utilities (staff sharing opportunities as well as infrastructure).

Summary

The co-operative OT network is an innovative solution created by the co-operation and sharing of existing and new communications assets between utilities. In the context of South Africa, this would consist of collaboration between the municipalities and national transmission operator to create a ubiquitous communications platform. The process to create such an environment will not be easy, but the idea may well be worth considering. As with many countries, South African utilities are all faced with business challenges associated with creating cost efficiencies whilst at the same time having to support new initiatives such as smart grid and smart metering. The OT network underpins all of these current and future services, and a co-operative network has the opportunity to meet the demanding requirements of the utility operation and provides a level of future proofing whilst reducing the overall investment and cost exposure of an individual utility. In essence, a solution where the achieved outcome "is greater than the sum of its parts".

Contact Paul Renshall, Mott MacDonald, paul.renshall@mottmac.com

ZigBee as a technology platform for advanced metering infrastructure (AMI)

by James Colmeyer, Strike Technologies

According to NRS049-1 (rev.1, 2010) for advanced metering infrastructure, the communications medium that connects devices in the system downstream of the data concentrator can either be power-line carrier (PLC) or wireless radio frequency (RF). These devices comprise single and three-phase metering, appliance control relays and customer interface units. Each of these two communication platforms holds benefits and disadvantages in terms of system costs, functionality and reliability. The challenge for utilities and municipalities is to find the applicable technology that will provide the solutions they require at the least cost.

The purpose of this paper will be to explain the functionality and security of the ZigBee wireless RF platform, to highlight instances where this technology provides superior capability and to provide tools with which to calculate the costs of deployment. The paper will provide reference to the deployment of this technology as part of the residential load management project roll-out, as funded by Eskom IDM, at the Municipalities of Drakenstein, Overstrand, Stellenbosch and Mossel Bay, which collectively make the biggest ZigBee platform roll-out in South Africa to date.

What is AMI?

Advanced metering infrastructure (AMI) is an enabling technology solution that provides near real-time customer specific usage data for energy management purposes. It refers to a system that collects, measures, analyses and controls energy usage by enabling data to be transmitted over a two-way communications network. AMI has the capability to drive significant business, customer, and environmental benefits including energy awareness, conservation and operational efficiencies, particularly in the area of field services.

AMI provides energy providers with unprecedented system management capabilities, allowing for the first time the possibility of having end-users make informed real-time decisions about their energy usage by acting as a gateway technology to the "smart home". AMI is overlaid on an interconnected network of smart meters, intelligent devices and the energy provider's control systems. A smart meter generally refers to a type of advanced meter that identifies consumption in more detail than a conventional meter. Smart meters record how much electricity is being used and when it is being used, such as half-hourly consumption. Smart meters include the ability to:

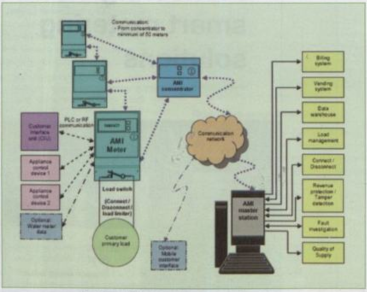

Fig. 1: Typical AMI system infrastructure using data concentrators.

- Remotely turn power on or off to a customer.
- Remotely read usage information from a meter.
- Detect a service outage.
- Help detect the unauthorised use of electricity.
- Remotely change the maximum amount of electricity that a customer can demand at any time.
- Support remotely changing the meter's billing plan from credit to prepay as well as from flat-rate to time-of-use tariff.
- Support bi-directional metering.

AMI in the context of NRS049-1

The NRS049 specification is focused on the advanced metering infrastructure (AMI) for residential and commercial customers and has been drafted and published to create a standard specification for AMI systems in South-Africa. An NRS049 compliant smart metering system essentially has the following characteristics (as illustrated in Fig. 1):

- Bi-directional communications from central server to meters and devices and from these devices back to the central server.
- Customers are able to have a portable customer interface unit in their premises that can read information off a meter and receive information from the utility.
- The ability to control up to two relays for load control (such as hot water cylinder and a swimming pool).
- Be capable of remote load disconnect for revenue protection of the utility.

In terms of this specification, it is envisaged that either power-line carrier (PLC) or radio frequency (RF) communications would be deployed between individual meters and the data concentrator, with the communications between the data concentrator and the master station typically through the cellular network.

ZigBee RF technology

ZigBee is a global wireless language connecting dramatically different devices to work together and enhance everyday life.

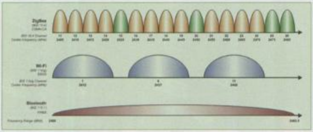

Fig. 2: Frequency spectrum allocation of the 2,4 GHz band.

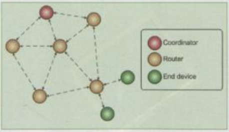

Fig. 3: Typical ZigBee network elements.

ZigBee and IEEE 802.15.4 are standards-based protocols that provide the network infrastructure required for wireless sensor network applications. 802.15.4 defines the physical and MAC layers and ZigBee defines the network and application layers. Typically where sensors are used, the key design requirements revolve around long battery life, low cost, small footprint, and mesh networking to support communication between large numbers of devices in an interoperable and multi-application environment.

There are numerous applications that are ideal for the redundant, self-configuring and self-healing capabilities of ZigBee wireless mesh networks, including:

- Energy management and efficiency as a result of improved information transfer and corresponding direct load control.
- Home automation to provide greater control flexibility of lighting, heating and cooling, security and home entertainment systems from anywhere in the home.
- Building automation for centralised control of lighting, security and HVAC applications.
- Industrial automation to increase the reliability of manufacturing and process control systems.

The interoperable nature of ZigBee means that these applications can work together, providing even greater benefits.

ZigBee channels and frequencies

The RF spectrums and available channels for ZigBee (802.15.4) and Wi-Fi (802.11b/g) overlap. These compete on the licence-free 2,4 GHz band. ZigBee has the ability to be agile across 16 channels in this band as illustrated in Fig. 2. Interference can be minimised by selecting ZigBee channels that use the free space between two neighbouring 802.11 channels (the Wi-Fi channels) as well as channels 25 and 26.

ZigBee network topology and device types

ZigBee networks are primarily composed of three types of devices, namely co-ordinators, routers and end devices. Co-ordinators control the formation and security of networks, routers extend the range of networks and end devices perform specific sensing or control functions. Manufacturers often create devices that perform multiple functions, for example a device controls a geyser and also routes messages to the rest of the network. The typical interaction between these three types of devices is illustrated in Fig. 3.

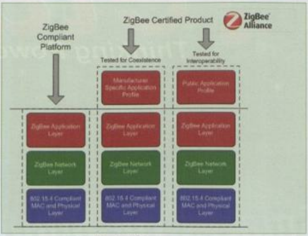

Fig. 4: Certified ZigBee testing programmes.

ZigBee communication reliability

In terms of network reliability, ZigBee was designed for the hostile RF environments that routinely exist in mainstream commercial applications. The language uses direct sequence spread spectrum (DSSS) with features including collision avoidance, receiver energy detection, link quality indication, clear channel assessment, acknowledgement, security, support for guaranteed time slots and packet freshness to offer product manufacturers a highly reliable solution.

Product certification and the ZigBee Alliance

The ZigBee Alliance is an association of over 285 companies working together to enable reliable, cost-effective, low-power, wirelessly networked, monitoring and control products based on an open global standard. Their focus is on the following:

- Defining the network, security and application software layers.
- Providing interoperability and conformance testing specifications.
- Promoting the ZigBee brand globally to build market awareness.
- Managing the evolution of the technology.

For a product to carry the ZigBee alliance logo, it must first successfully complete the ZigBee certification program. This ensures that the product complies with the standards described in the ZigBee specification. There are two ZigBee certified testing programmes (see Fig. 4):

- ZigBee compliant platform. This programme applies to modules or platforms that are intended as building blocks for end products.
- ZigBee certified product. This programme applies to end products that are built upon a ZigBee compliant platform. After successful completion, these products can display the ZigBee logo.

Products that use public application profiles are tested to ensure interoperability with other ZigBee end products. Products that use manufacturer-specific profiles, which will operate as "closed systems", are tested to ensure they can co-exist with other ZigBee

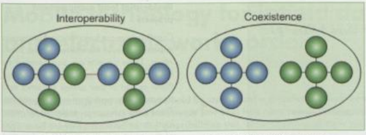

Fig. 5: Graphical explanation of co-existence and interoperability of ZigBee products.

systems (see Fig. 5) to ensure that they do not adversely impact the operation of other ZigBee-certified products and networks.

Security on a ZigBee network

ZigBee security, which is based on a 128-bit AES algorithm, adds to the security model provided by IEEE 802.15.4. The security services include methods for key establishment and transport, device management, and frame protection. Use is also made of trust centres (typically the ZigBee co-ordinators but can also be a dedicated device) that decide to allow or disallow new devices into the network. The trust centre may periodically update and switch to a new network key. It first broadcasts the new key encrypted with the old network key and then subsequently tells all devices to switch to the new key.

ZigBee in AMI applications

Typically, the data concentrators would act as coordinators and would establish a ZigBee cloud on their secondary side with the primary side communications being the backhaul over cellular or Ethernet to the AMI master station. All system components connect into this cloud and pairing is authorised by the data concentrator. Essentially any components from an adjacent cloud may be able to see the first cloud but do not participate in the conversations due to pairing. The shape of the cloud follows each device as each component in the system propagates the ZigBee cloud. Each device in an AMI system ideally acts as a signal repeater or router. The benefits of using the ZigBee wireless communications platform for the last-mile communications includes the following:

- The ability for the network components to expand the RF mesh (all repeater functionality). This results in a more stable communications network with a better and wider reach. The added benefit of this in terms of costing is that fewer GPRS/GSM cellular connections would be required due to a lower number of concentrators. This ensures lower operational costs too that makes RF based systems for more cost effective.
- Price competitive in environments with a low geographical penetration of high-value consumers because of lower concentrator requirements. As a result of this, RF solutions can be extremely price competitive with PLC type systems as you are not limited to the local transformer level. This assumes naturally that the RF signal propagation is properly designed and deployed.
- Capability for flexible metering system configuration according to customer requirements i.e. split meter and control relay. There are no requirements to install cables between meters and the customer interface units.
- Not limited to two controllable loads per household i.e. can be expanded as the needs of the utility change and a more financial prudent phased-approach can be used.
- Loads can be controlled at the end load and are measured (and monitored for disconnect or bypass).
- Free from constraints in a "dirty" power system where the reliability of PLC comes into question.
- The RF network is self-learning, self-managing and self-healing ("place and forget") which will ensure a lower level of maintenance and a higher level of reliability for the utility and the customers.
- Ability to do OTA (over-the-air) firmware updates to all system hardware at an acceptable speed whereas the low baud rates of PLC make this extremely difficult and unreliable.
- Software tools are easily available to interrogate, plot and evaluate the real-time status and health of any zone of the mesh network (see Fig. 7).

AMI system cost

The emergence and maturity of cellular technology has enabled the growth of automated meter reading (AMR) and AMI platforms and rendered them as viable solutions. Typically this is achieved with an access point name (APN) which allows metering to be allocated a unique IP address.

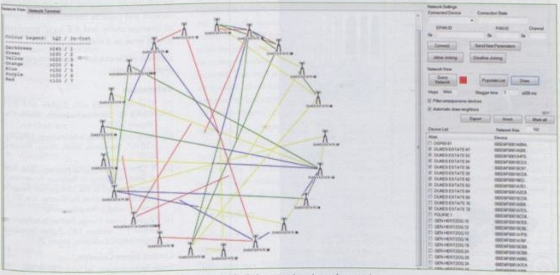

Fig. 6: Sample of a ZigBee network analysis software tool.

$$C_{AMI} = \left(M_{TA} + \frac{M_C + C_{GSM} \cdot p}{R}\right) \cdot n + (S_{APN} + C_{APN} \cdot p)$$

where:

C_{AMI}	=	Total AMI platform cost
M_{TA}	=	Hardware cost of the AMI ready meter
M_C	=	Hardware cost of the GSM/GPRS ready data concentrator
p	=	Project period (months)
C_{GSM}	=	Cost per meter or connection per month for GSM network traffic (including SIM card)
R	=	Concentration ratio of meters per data concentrator
n	=	Number of metering points or end-users
S_{APN}	=	Initial setup costs for an APN system
C_{APN}	=	Fixed cost per month for an APN (irrespective of usage)

Eqn 1: Costs of an AMI system.

The costs involved with an APN typically include the following:

- S_{APN}: Initial setup costs for an APN system.
- C_{APN}: Fixed cost per month for an APN (irrespective of usage).
- C_{GSM}: Cost per meter or connection per month for GSM network traffic (including SIM card).

The initial setup costs (S_{APN}) include the APN creation as well as the installation of leased lines (or similar connectivity) between the GSM network and the master station server.

In smart metering or AMI systems, the GSM connections are drastically reduced because they are only required for backhaul to and from each data concentrator. Each data concentrator then communicates with each meter connected to it (anywhere from 20 to 500 devices or meters) using either power-line carrier (PLC) or wireless RF (ZigBee) communications. In AMI systems the cost of the last mile communications (PLC or RF) is usually included in the hardware cost and does not involve licencing or monthly fees. The costs of an AMI system are represented in Eqn 1.

Residential load management projects

Currently there are four municipal projects in implementation in the Western Cape, South Africa. These projects are partly funded by Eskom Integrated Demand Management (IDM) as part of their energy efficiency and demand-side management programme. These projects focus on residential hot water load control using the load control portion of the smart metering or AMI (automated metering infrastructure) system. The projects in question will enable Eskom and the various municipalities to shed load during peak times as follows:

- Stellenbosch (5,07 MW)
- Overstrand (3,160 MW)
- Drakenstein (7,204 MW)
- Mossel Bay (4,687 MW)

Each system runs independently from the others and is based on a site deployed central server from which signals are distributed via GPRS to data concentrators and from the concentrators signals are distributed via ZigBee RF to the appliance control devices that will switch the hot water cylinders (geysers). The relative size of these projects in terms of hardware is as follows:

- AMI master station (4 instances)
- Data concentrators (~87 units)
- Appliance control relays (~43 400 units)

Conclusion

The business case for AMI is increasingly focused on driving efficiencies in energy consumption and business operations. Although the technology aspects of AMI are significant, the business outcomes are most important. AMI holds the promise of maximising the operating profit of the utility by influencing consumer behaviour against network and capacity constraints. The issues of interoperability and the local standards should serve as a means to this end.

ZigBee is viable as a last-mile communications platform for AMI.

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Contact James Calmeyer,
Strike Technologies, Tel 011 635-8000,
jamesc@strike.co.za

Mobile technology for infield data collections and electronic works orders

by JH Götze, Motla Metering

Mobile technology has taken the world by storm and is developing further every day. The capability of transferring data over GSM networks at a relatively low cost has also revolutionised the world even more than the industrial age and there is no end to the possibilities yet. New ideas and new processes are now possible in the field of infield data collection.

This paper will deal with a simple, but effective and cost saving application of the new age technology now available to us that will assist municipalities to reduce costs and improve services.

In field data collection has always been a challenge with data collectors making use of paper or a handheld electronic device to capture the data and a separate GPS and a separate camera to take the photos. Linking all these to the same and correct data bundle sometimes proved to be impossible. With new handheld technology incorporating all these features the data collection process has been simplified resulting in improved data received from the field. The GSM network data capabilities now also make it possible to receive this data from the field real time with huge advantages.

Data in the municipal environment

Data in the municipal environment can impact hugely on the services delivered and the cost effectiveness of the municipality. Incorrect billing data can bankrupt a municipality and incorrect data on which maintenance efforts are based will cause huge additional costs and slow service delivery. Some typical data used by municipalities are:

Customer data

- Personal information
- Address
- Property

Meter data

- Meter information such as type, make, number, etc.
- Position
- Condition
- Average consumption
- Maintenance required

Asset register

- Asset type
- Position
- Value
- Condition
- Maintenance required

There are many more data sets used and these examples above can each be extended into subcategories extensively as well. It is not the purpose of the paper to list data sets and types, but to illustrate that municipalities rely heavily on data to operate. As does any business in the new age of information technology. Incorrect data costs money.

Origin of municipal data

Historic data

Municipalities have large data sets that stem from many years of doing business and many years of gathering data from the field. The accuracy of this data is mostly in question as it was gathered using paper infield data capturing techniques and is mostly incomplete as well. This leads to incorrect decisions made as far as proactive maintenance and large billing errors are made as a result of these incorrect data sets. The results are huge losses and inefficiencies. The worst of these are the errors that are not evident and that no-one knows of.

Infield data capturing projects

At some stage all municipalities undertake some sort of data collection project to update the historic data and/or gather data not previously required. These projects are mostly outsourced and many times the focus is on the price and how quickly the data can be collected instead of on the quality of data received. The result is normally incorrect data as a result of contractors rushing to avoid penalties for late completion and due to short cuts taken to save costs.

Much of the data is also received from maintenance teams. This information is normally on paper and sometimes never reaches the data base. Monthly processes such as meter reading and credit control are also sources of data.

The solution

Define processes in advance to maintain all new and old data

Data sets are "living organisms" in the municipal environment due to maintenance programs, upgrade programs and movement and behaviour of consumers. Processes that will define what must be done with data and how it is done must be defined clearly and these must be managed strictly. History of data must be kept and all changes to data logged. Access to data must be managed and user rights must be well defined.

Define processes to incorporate the new data with the old

What to do when newly collected data and the historic data are different? What can be trusted? Normally the historic data will have the least impact on the customer and cause the least amount of work for the municipal official and is therefore accepted as correct, making data collection programs futile. Discrepancies should be investigated in detail and the correct data set used. Influences on customers must then be communicated with the customer, but the correct data must be implemented.

Define processes to collect the data

Processes to ensure that the collection of data is done effectively and accurately must be clearly defined. Deliverables and tolerances must be defined and statistically representative sample audits of data submitted must be done to ensure accuracy levels are maintained. Where access problems occur due to locked properties or due to denied access, clear and decisive action must be taken to ensure access is obtained. Suspension of the supply of services is a strong tool to use and works very effectively. There is no quick fix when it comes to data purification and therefore sufficient time must be allocated to the data collection process.

Manage the data user and collector, not the data

If the user and the collector of data is managed to operate within strict boundaries the data will look after itself. Data cannot corrupt itself. It is always corrupted by the action of a human being. Therefore human intervention must be reduced to a minimum. All human interaction must be monitored, reported on and corrective action must be taken if errors were made.

Make use of technology

Technology as discussed in the introduction is available to manage data users and collectors. Most processes and procedures can be enforced using technology. This will be discussed in more detail below.

Maintain the data continuously

Data can be maintained successfully if all users of data are managed to ensure processes and procedures are adhered to. The maintenance effort must be continuous with immense discipline. Systems and technology cannot prevent the effects of ill discipline completely.

Technology

GPS

GPS technology cannot just tell you where an asset is located, but assists in managing personnel who have to visit the asset.

Personnel management

Due to the fact that you can track personnel you can report on how long the person took to complete a specific task and how long the person spent on the road to get there and back. This information is invaluable as management of field personnel is now possible from a desk. Efficiencies improve with huge cost reduction as a result and with improved reaction times and improved service delivery. Planning can be done more effectively in terms of the number of personnel required, and equipment that is required will reduce as the number of personnel is reduced. A case study on meter reading will show the effect of this later in the paper.

Spatial reporting

Spatial reporting on consumption, maintenance frequencies, credit control actions, access to meter problems, etc. is now possible. A picture says a thousand words. This is a very useful tool to evaluate data received. When reporting spatially you can easily see from meter reading data where there are stands with electrical meters, but no water meter associated with the same stand. This can be investigated and corrected resulting in additional income. Consumption data can be shown spatially and when a stand does not have consumption similar to those in the same area, it can be identified and investigated.

Routing

Work in certain areas can be combined to be allocated to technicians to ensure travelling is optimised. Urgent work can be sent to personnel who are in the area. Meter reading routes can be optimised, resulting in fewer resources required. Personnel can be routed to the asset for maintenance purposes and even for meter reading purposes.

General

If a GPS co-ordinate is taken every time an action such as meter reading is taken, this co-ordinate can be used to verify whether the work was actually done at the meter or not. IT can therefore be used as a "policing" tool to ensure personnel are kept honest.

Visual aids

Photos of assets can assist in the planning of maintenance. Know what is required to be done and what tools and parts are required to complete the maintenance before you go to site. Travel time will be reduced and personnel can be employed more productively. Huge cost savings can be achieved by providing information to customers who may query meter readings as no additional test reading is required. Again a picture says a thousand words and cannot be disputed. It can also serve as evidence when tampered meters or illegal connections are photographed with a date and time stamp. Photos are very successfully used to verify meter readings as new processes force the meter reader to take a photo when the system does not agree with the reading or when a maintenance code or no access code is entered. If all maintenance technicians are forced to take photos of work done it can be used to do quality assurance as well. A very simple application is to force any person who opens and closes a meter box to take a photo of the box once the task is completed. There will be no more open meter boxes.

GSM

Real time communication has become essential in the meter reading industry and will also become essential in all facets of the municipal business. Just as we cannot imagine what we did to communicate before cellphones, we will in future wonder how we managed our business without real time data communication. In some instances it is already a reality with smart phones now receiving and sending e-mail and with smart meters communicating in real time with servers all over the world, not to mention old technology such as telemetry and SCADA systems. The meter reading industry is now using real time data transfers to manage the quality of readings and to reduce turnaround times. Data is validated on the handheld, but is then sent to the server for further validation and can be sent back to the meter reader to confirm while the reader is still in the field. Progress of meter readers is monitored in real time. Reading of remote areas can now be done much more cost effectively as no one has to collect a handheld device from the office to go and read the remote area. A person in the area can download the electronic works order and read the meters. This is especially effective where municipalities consist of various rural towns.

Electronic work orders/job cards

With electronic works orders, a higher level of control is possible resulting in improved quality of work and improved efficiency:

- Processes can be forced onto the person who has to fulfil the work issued on the works order.
- Photos can be made compulsory and the works order cannot be closed if the photo was not taken.
- GPS co-ordinates can be taken in the background to ensure no control over this function is possible and therefore keeping the person honest.
- Certain data fields to be captured can be made compulsory ensuring essential information is received back.
- Drop down menus can be used to ensure there is only one way of spelling "Church Street".
- Completed works orders are uploaded onto the central data base via GSM as soon as it is completed. Now all the information is available for use and for feedback to customers.
- Data is not just loaded onto the system automatically, but is done so accurately.
- Data validation can be done on the handheld before it is accepted and all required data is forced to be entered.

Case study

Background

Meter reading has always been underestimated in both the value it can add in terms of data from the field and in terms of the importance of the function in the revenue chain. The meter is the cash register of any municipality and must be managed as such. Imagine where Raymond Ackerman would be if he did not manage his cash registers properly. It is essential that municipalities come to realise the importance of the meter reading function. It is no longer just about getting a reading for every meter. It is about data collection on the meter and on condition of the meter and factors that make reading the meter impossible. It has become important to report accurately why a meter cannot be read as this will influence the maintenance required and done immensely.

Ekurhuleni is an example of a municipality that realises the importance of this reporting. Consultants are appointed to manage the meter reading and maintenance of meters and as a result the importance of reporting on meter condition has become part and parcel of the meter reader's function and a very important part thereof. The asset (meter reader) paid for is used optimally by making use of the data received from the asset.

Realising this need, a system was developed that incorporated all the above technology and processes were developed to force the

meter readers in the field to collect the required information and to do so accurately.

GPS technology implemented

- GPS co-ordinates are taken in the background for every action taken and are date and time stamped.
- GPS technology directs the meter readers on the handhelds to the next meter to be read.
- Spatial reporting is available.

Photos

Photos are forced for the following outcomes:

- No access codes
- All maintenance codes
- All note codes
- All high/low exceptions

Quality assurance rules built in

The following rules are programmed onto the handheld to assure correct data is reported:

- Confirmation of the address.
- Confirmation of the meter number.
- Evaluation of the reading in terms of the average consumption.
- Evaluation of the no access code, maintenance code and note code in relation to the history of previously reported codes.
- Confirmation of the GPS co-ordinate in relation to previous GPS co-ordinates taken for the meter.

Strict processes are enforced for certain outcomes. For example if a reading is not within preset limits according to the average consumption, a photo is forced and the reading must be re-entered backwards.

If a maintenance code is not the same as the previous month, a code is suggested.

The following rules and processes are built into the back office system:

- All entries with a photo are flagged and investigated by a data analyst.
- The photo is used to determine if the data received is correct or not. If the data is not correct or if the photo is not of good quality, the data analyst sends an electronic works order to the meter reader or the supervisor in the field to re-read the meter.
- The data is then again put through the same quality check.

Case study results

Data accuracy

- Meter reading data accuracy where actual readings were entered improved from 97% to 99%.
- Accuracy on maintenance codes increased from 80% to 99%.
- Accuracy on no access codes increased from 80% to 99%.
- The most significant improvement was on the number of meters read. This increased from 80% to 87% due to a reduction in the number of no access codes provided and due to more effective maintenance.
- Readings directly onto bill increased from 77% to 86%.

Cost reduction

A cost reduction of 15% was experienced by the meter reading company due to less transport of personnel required and due to increased efficiency of meter readers. If routes could be optimised a further cost reduction would have been possible, but due to the fact

Continued on page 49...

Half-cycle circuit breaker for rural smart grids minimises operating costs of feeder, spur lines

by Dr. Brett Watson, Dirk Scheerer, and Benjamin Gischke, Siemens

Rural electricity distribution is less reliable and more expensive to operate than urban networks and generates less revenue. Long overhead line lengths, inherent high fault frequency and the often considerable time taken to find and access faults result in long outage durations, poor regulatory performance and, often, financial penalties.

Long lengths of line that generate little income can be financially problematic for utilities even when they operate reliably. Lines with high fault frequencies and which serve few customers are more than challenging. They require investment to improve reliability performance, but with few customers it is difficult to justify the capital expenditure necessary to improve them.

This paper proposes ten criteria that represent the ideal network performance of rural overhead spur line protection devices. These criteria are then used to evaluate and compare the rural network performance of three low capital cost protection devices. Two of these solutions are traditional devices, the common fuse and the drop-out sectionaliser. The third is a new compact, intelligent and fast circuit breaker technology recently developed.

Rural network overview

Rural overhead, medium voltage distribution networks are normally configured as radial networks. A zone substation will have a number of feeder lines emanating from it. Each of these feeder lines will then have tee-off spur lines feeding clusters of customers. There are few, if any, interconnections between feeder lines. Fig. 1 provides a typical network topology that will be used for the performance comparisons presented later in this paper.

Rural networks also tend to experience high fault rates due to storms, lightning, vegetation and wildlife. A typical fault rate which provides a reasonable guide to network performance and which is used in this paper for later comparisons is that a rural spur line that experiences 0,02 faults per km per year [1]. For example, a 50 km spur line will, on average, experience one fault per year.

Fault types can be classified as transient or permanent. A transient fault means that the electricity supply is turned off momentarily and that the fault will be gone when the line is re-energised. A permanent fault infers that the line has experienced permanent damage and the fault cannot be cleared by a momentary interruption to supply. A line crew must physically repair the damage before re-energising the line. For a rural overhead network, typically 70 – 80% of faults are of a transient nature. This high proportion of transient faults has implications for optimisation of rural network performance.

Rural networks are also characterised by their large geographical size and low customer density. This means that the operating costs to own and run the network are high, especially considering the high fault rates, but that the revenue generated is low. Outages that require line crew attendance incur high operating costs due to the long drive time to find the fault and access the site. In addition, potentially substantial penalties may be incurred from regulators for these long outages. These factors have significant implications on the scale and type of investment that network owners are prepared to make on their rural network. Low cost of purchase, installation and ownership are all key drivers for rural network investment to improve network reliability.

Ideal spur line protection characteristics

As the majority of line length in rural networks is attributed to spur lines rather than to the feeder line, this paper will examine the protection options at the spur line level for faults that occur on the spur line. This paper will assume the feeder line is protected by a recloser with electronic control as in Fig. 1.

In investigating the performance of rural spur lines, ten performance criteria have been introduced that, when implemented in a protective device on the spur line, provide the optimal network performance [2]. These ten criteria are listed and explained in Table 1.

Evaluation of spur line protection solutions

Currently, the most common devices used for the specific protection of spur lines are a traditional drop-out fuse or a drop-out sectionaliser. This paper evaluates each of these devices and compares it to a new, intelligent fuse-saving circuit breaker. The authors acknowledge that other devices are also available for spur line protection

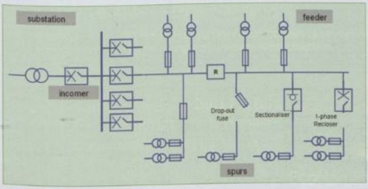

Fig. 1: Typical rural network topology.

Fig. 2: A traditional drop-out fuse. [3]

Performance capability	Explanation
Interrupt fault current	The rural spur line protective device must be able to interrupt fault currents appropriate for this part of the network. An additional aspect of this is for the device to have adequate protection reach to pick up relatively low level faults.
Only spur line customers experience an outage	For any fault that occurs on a given spur line, only customers on that spur line should experience any outage, either momentary or sustained.
Transient faults should not cause a sustained outage	If a fault is transient, it should be cleared in such a way that power is automatically restored to the spur line customers after only a momentary outage.
Provide a visual indication of a permanently faulted line	If a line has a permanent fault that has caused the spur line protection to operate, the protective device should provide line crews with a clear visual indication of which spur line is faulted.
Record information about fault and line operation history	The rural spur line protective device must record historical information about events that have occurred on the spur line. This event history should include information about when events occurred and, in particular, details about faults such as phase and magnitude of fault current.
Provide a visible point of isolation	During some network maintenance activities that cannot be carried out live-line, spur lines may need to be electrically isolated and have a visible point of isolation to comply with network safety requirements before work can be commenced.
Improve safety of live line crews	The spur line protective device should be able to improve the safety of live-line crews when working on energised spur lines. This should be achieved by means of fast and sensitive protection to clear faults in the case of accidents.
SCADA integration capability	To facilitate a real smart grid, all protective devices should have the capability of being integrated into the network SCADA system. This provides the following key benefits: • Device status information reported in real time to control centre to allow notification of faults and outages. Allows efficient management of line crews during storm events. • Remote switching of devices. • Remote reconfiguration of devices. • Remote access to event records.
Low capital cost of equipment	The purchase price of devices for rural spur line application must be low to provide an attractive return on investment to utilities.
Quick, easy and cheap to install	The installation cost of devices for rural spur line application must be low to provide an attractive return on investment to utilities. This means quick installation times, using live-line techniques with no additional lifting equipment required.

Table 1: Performance criteria for optimal spur line protection.

including the use of reclosers. These have not been included as in most cases the cost justification for use on rural networks is not possible.

Traditional drop-out fuse

Most rural medium voltage networks are configured with the primary feeder protected by a circuit breaker or recloser, while a fuse protects the spur line (see Fig. 1).

When a fault occurs on the spur line the fuse operates to clear the fault. When the fuse protection is graded correctly with the upstream recloser, the recloser will never need to operate on a spur line fault. This means only the customers on the faulted spur line experience an outage. The problem with this configuration is that the fuse blows on all faults, both permanent and transient, causing downstream customers to always experience a sustained outage and always requiring a line crew to replace the fuse incurring substantial operating costs for the network owner. In most cases this sustained outage is unnecessary as the fault is transient.

A fuse that has blown will drop down and provide a visual indication to passing line crews as to the faulted line. When in the dropped down position the fuse provides a genuine electrical isolation due to the large air gap.

A fuse has no electronics or intelligence and therefore no capability to record historical data about fault events or reliability data. Without communication functionality, it cannot communicate device status remotely. It makes no contribution to the formation of an intelligent grid.

When a live-line crew is working downstream of a fuse, the operating time of the fuse is dependent upon the fault level. As such, normal practice is to use the feeder line recloser with a hot line tag setting as the protection for the live-line crew. Even the fastest recloser protection will allow 2 – 3 cycles of current to flow, which is adequate to cause significant burns to an operator in case of an accident.

While fuses possess a low capital cost, up to 80% of fuses blow unnecessarily. While fuses are quick and easy to install on-site, a line man or crew in an average rural environment may take hours to travel, patrol the line for potential fault, search for and repair the blown fuse, costing the utility in the order of R10 000 for a single fuse operation. This represents a substantial cost of ownership if a line has frequent faults and is therefore a false economy.

Drop-out sectionaliser

Drop-out sectionalisers are used in place of the spur line fuse and are partnered with the feeder line recloser. When a fault occurs on the spur line, the drop-out sectionaliser does not have a fault interrupting capability of its own and relies upon the recloser to clear the fault. If the fault is transient, the recloser will clear the fault. However, in doing so, it will give all customers downstream of the recloser a momentary outage, not just those on the faulted spur line. If the fault is permanent, the sectionaliser monitors the fault current and the reclose sequence, and opens during the dead time of one of the reclose operations according to the configuration set. Essentially, the feeder line recloser is used to clear transient faults and the sectionaliser is used to isolate a permanently faulted spur line. Unfortunately, the majority of spur line faults are transient.

As the recloser protection settings must take account of the load currents generated from all downstream customers, the pick-up current can be much higher than is ideal for spur line protection where the fault has actually occurred. This means that low level faults at the end of a spur line may not trigger the recloser protection at all. This can result in serious safety events such as pole top fires or downed conductors that are still energised.

A sectionaliser that has operated provides line crews with a visible break at the site of the operation, but without fault interrupting

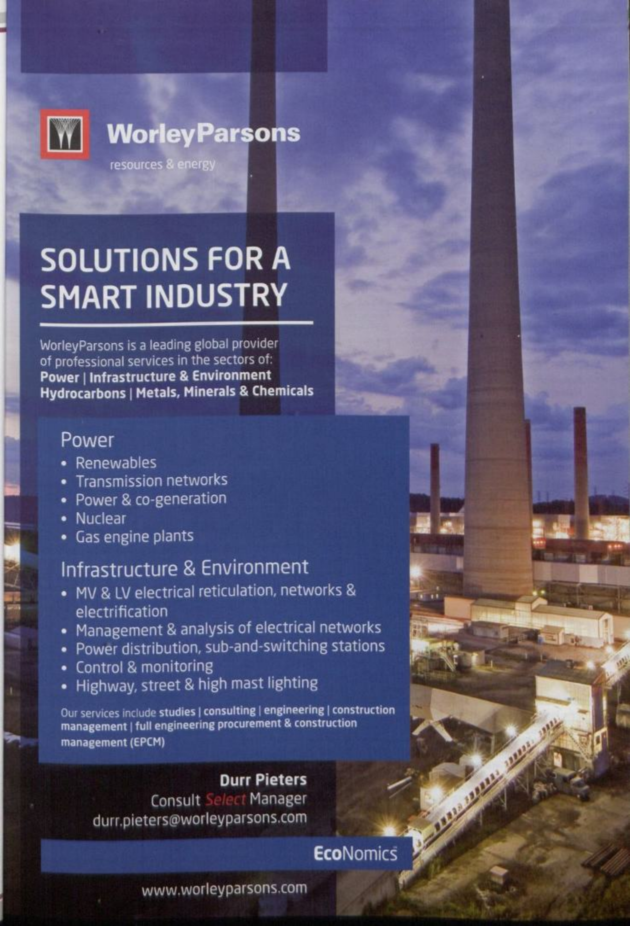
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Fig. 3: A typical drop-out sectionaliser [4].

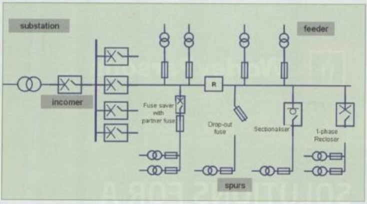

Fig. 4: The fuse-saver and fuse partnered on spur line.

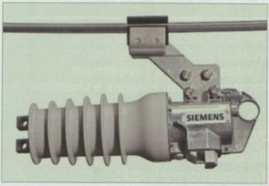

Fig. 5: The fuse-saving device.

capability, offering no rapid or sensitive fault protection to line crews. Again, the upstream recloser hot line tag must be applied. Therefore drop-out sectionalisers do not improve the safety of line crews.

Furthermore, the sectionaliser has no internal fault memory capable of maintaining a record of outage events. No event log or line history exists to assist the network operator to understand the reason for the outage, nor to maintain an accurate record of the length of the outage for performance reporting purposes. It cannot be integrated into a network's SCADA system, has no capacity for remote control and does not enable operators to transition to an intelligent network.

The purchase price of the sectionaliser is relatively low, and the device itself is simple to install and replace.

Fuse-saving circuit breaker

This newly developed device is a self-powered, electronically controlled, single-phase fault-interrupting device that is installed in series with a fuse (see Fig. 4) to protect the fuse from transient faults. This "fuse-saver" detects, opens and clears a fault in as little as a half-cycle which, for most rural spur line faults, is less time that it takes for the fuse to melt. It then automatically closes after a configurable dead time.

If the fault was transient, then only the spur line customers have experienced a momentary outage. If the fault is permanent, after closing, the fault current will flow again and the fuse will now operate to clear the fault. The fuse drops down, providing a visible flag to line crews of the permanently faulted line and electrical isolation. Again, only the customers on the faulted spur line experience an outage.

When line crews are working downstream, the device's protection functionality can be changed to a single shot to open mode with instantaneous protection by pulling down the "protection off" lever. This means that all faults will be limited to a half-cycle duration and the consequences of accidents during live-line work are greatly reduced and survival chances increase.

This device has on-board electronics with memory that contain an event history, including information on fault characteristics. A short-range wireless communication module is easily attached to each device allowing connection to a custom PC application. This enables an operator to view live data on the status of each installed device, including the time, type and magnitude of the most recent fault. Event logs from multiple spur line fuse-saving devices can be retrieved and analysed to determine the worst performing spur lines allowing network owners to take preventative action in a cost effective manner. Furthermore, a utility can gather accurate, reliability data on their network performance for use in regulatory reporting, leading to financial savings.

Using short-range radios, the devices on multi-phase sites can communicate and work as a team to further improve network performance. Synchronous manual tripping and closing is possible to avoid ferro-resonance issues. Also, when one phase experiences a permanent fault the devices on the adjacent phases can be instructed to trip and to provide a three-phase lock-out to protect three phase machinery from damage.

A proprietary, purpose-designed remote control unit is available, enabling this device to then be integrated into a network's SCADA system, providing rapid access to data and remote access to devices from the central control centre. This includes receiving fault alerts and gathering reliability data.

Like traditional spur line protection options, this technology has a low capital cost, and is quick and simple to install, saving operational budget. Payback can be achieved in as little as a year, subject to fault frequency and reliability penalty schemes.

Comparison of rural network performance

A comparison of the three solutions examined in this paper using the ten network performance criteria is presented in Table 2.

Performance criteria	Fuse	Sectionaliser	Fuse saver
Improve operator safety	No	No	Yes
Interrupt fault currents	Yes	No	Yes
Only spur line customers affected by fault	Yes	No	Yes
Transient fault only causes momentary outage	No	Yes	Yes
Point of visible isolation of line	Yes	Yes	Yes
Visible indicator of permanent fault on line	Yes	Yes	Yes
Provides data on fault and line operation	No	No	Yes
Communicate location of fault	No	No	Yes
Event history for the line	No	No	Yes
SCADA integration	No	No	Yes

Table 2: Network performance comparison.

Conclusion

A comparison of the performance capabilities of the three solutions examined in this paper immediately shows that the fuse-saving device is the only one that meets all of the criteria for the optimal protection of rural spur lines.

Fuses, while the lowest cost option, are inadequate as they create a sustained outage for all faults when the majority of rural faults are transient. Drop-out sectionalisers require a much larger customer base to experience an outage to clear a spur line transient fault. Neither a fuse nor a sectionaliser has any smart grid functionality and certainly cannot be integrated into a SCADA system.

This evaluation finds that the new fuse-saving device is the only technology that can improve rural performance and cost, whilst building an intelligent grid for the future. It addresses all of the key performance capabilities required for an achievable, improved rural network performance today and a financially sustainable future.

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[3] www.diytrade.com/china/pd/8209383/outdoor_ac_high_voltage_drop_out_fuse.html.

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Contact Dr. Brett Watson,
Siemens, PO Box 4833,
Loganholme,
QLD 4129,
Australia

Impact of efficiency measures and distributed generation on municipal electricity revenue

by A Janisch, M Borchers and M Euston-Brown, Sustainable Energy Africa

A range of national and local policies and strategies promote energy efficiency and renewable energy in response to the electricity crisis and national climate change commitments. This trend is not only local, but global. In South Africa this is taking place in the context of rapidly decreasing renewable energy costs and simultaneous rapidly increasing grid electricity costs resulting from the new build programme.

Electricity revenue and city financial survival is closely linked in many South African municipalities, due to our particular history of municipalities operating as electricity distributors. Typically 10% of annual electricity revenue generated is fed into city coffers, subsidising a range of other important municipal services. In addition, revenue from "high-end" users (larger residential and other consumers) is routinely used to cross subsidise "losses" from providing power to poor households which are not fully covered by the national equitable share grant.

In the past, the threat of revenue loss linked to reduced sales from energy efficiency and solar water heating programmes has often resulted in some resistance by electricity departments to such initiatives. However, today it is widely accepted that such changes are inevitable, even if just as a consumer response to the high electricity prices and increasing availability of cheaper alternatives (e.g. solar PV), and a managed response is therefore called for.

The threats to electricity revenue remain real, and only recently has work started to assess this situation in detail. What will the impact be of "high-end" customers becoming more efficient and installing solar PV systems for own-use, because it makes financial sense – as is expected within a few years? [1]. These customers are key revenue generators for cities, and important for enabling cross-subsidisation of the ever increasing proportions of poor households. This paper presents results from a modelling exercise to estimate this revenue impact of efficiency and small embedded generation over the next 10 years, flags the potential for an impending revenue "death spiral" associated with expected trends, and suggests what needs to be done to avoid likely serious negative revenue consequences while still enabling economically desirable efficiency and renewable options.

Hourly load profile impact modeling

Discussions with municipal electricity staff indicate that general models projecting potential electricity and revenue savings and losses were not particularly useful, but rather hourly load profile impact analysis was required mainly because bulk purchase costs vary significantly at different times of the day and year. An immediate challenge to undertaking this exercise was that often cities don't know what their overall load profile is. To undertake the modelling, detailed half-hourly data was gathered for six intake points for the City of Cape Town and for key eThekwini intake points for a full year. Only results for Cape Town are presented here, as discussions with eThekwini officials on their results had not yet taken place at the time of writing. Load profiles included week and weekend demand.

Projections for uptake of various efficiency and renewable alternative energy services were developed. These concentrated on the residential sector (for which more detailed information was available, and which forms the focus of this paper), with some estimations for commercial building efficiency and broad estimates for industrial efficiency. Projections were developed based on "real life" data as far as possible:

- Residential uptake of efficient water heating based on market analysis undertaken for Cape Town City rollout programmes.
- Commercial building efficiency impact based on data taken from the real-time monitoring of eThekwini municipal buildings pre- and post-efficiency retrofits.
- Residential PV uptake based on a detailed analysis of customer expenditure on electricity and therefore PV financial feasibility into the future [2].
- Solar PV generation profile based on analysis of solar radiation data, with array tilt angle selected for maximum annual output (see Fig. 2).
- Predicted electricity price increases and PV price decreases as reflected in the national IRP2010.

Pulling these together resulted in the key inputs to the model given in Table 1.

As will be shown, the most significant amongst the interventions in terms of revenue loss are the solar PV uptake of 100 000 households in 10 years, and efficient water heater uptake of 350 000 households in 10 years. Both of these penetration figures are based on substantial research, and therefore are considered credible. These interventions will be primarily adopted by hi-end users who are most affected by increasing tariffs, which is compounded by the structure of the inclining block tariff (IBT) resulting in their bearing the brunt of price increases. Revenue losses from this category of customer are serious, as they

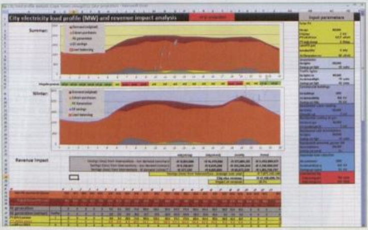

Fig. 1: Screengrab of load profile and revenue impact analysis spreadsheet model used.

Interventions modelled		
Solar PV (residential)		
No system	100 000	over 10 yrs
kWp/system	2	kWp
Commercial buildings		
No buildings	1000	over 10 yrs
Av demand/bldg	550	kW
Savings per bldg (pk)	50	kW
Residential water heating*		
No. SWHs	350 000	over 10 yrs
Demand / cyl	3	kW
Residential LED downlighters		
No lights	300 000	over 10 yrs
Savings per light	40	Watts
Residential eff showerhead, geyser blanket		
No installations	300 000	over 10 yrs
Savings per install	3%	
Industrial load reduction		
No customers	1000	over 10 yrs
Av demand/cust (pk)	600	kW
Savings per cust.	5%	kW
** Residential eff water heaters equipped with timers to avoid peak load periods (i.e. megaflex peak)*		

Table 1: Interventions modelled.

are key to cross-subsidising other city functions as well as low income household electricity provision.

Commercial and industrial solar PV uptake, which is expected to be significant, was not modelled in this first exercise. This impact will be explored in future work.

Load profile modelling results

The graph in Fig. 2 shows the result of the hourly load profile modelling for Cape Town for the different interventions discussed above. The major contributor to the efficiency intervention impact (shown in blue) are solar water heaters. Note that these are equipped with timers to avoid megaflex peak periods, thereby maximising their benefit for the city by smoothing the load profile. Solar PV is shown in yellow at the bottom, and while it has a small apparent impact, the revenue impact is significant (discussed later).

Reflecting on this graph the following points are noteworthy:

- Interventions that can hit megaflex peak periods are obviously the best. At this point the municipality is often selling electricity to the end user for less than they are purchasing it from Eskom (particularly in the residential sector) and therefore any load reductions here are potential money savers. Solar water heaters with timers to avoid peak periods are one such intervention (although they will still result in a revenue loss with current tariff systems, but this loss will at least be minimised by the use of timers).
- Solar PV systems generate most of their power during the day rather than in peak periods. At these times bulk power purchase costs are generally at standard rates, and thus the revenue losses from displaced power are more significant.

Electricity revenue impacts

The graphs in Fig. 4a and 4b indicate the impact of the different interventions on electricity revenue. Of most interest are solar PV and solar water heaters. Other interventions (commercial and industrial efficiency, and other residential efficiency measures) also have important impacts, but these are not the focus of this paper. The impact shown in the graphs of solar PV and solar water heaters (SWHs) are clearly significant, particularly when net (operating) revenue is considered (i.e. where bulk purchase expenses are excluded, which are around 63% of total expenses for Cape Town at present, and are likely to escalate to over 70% as electricity prices increase faster than inflation). The net revenue impact reflects the real effect on the income available to the electricity department for core functions, as well as for contributions to other important city functions.

The losses indicated are clearly untenable. Should current PV price trends, solar water heater rollout expectations, electricity price escalations and tariff systems persist, revenue losses are predicted to be around 6% of total revenue (and probably around 26% of net revenue after deducting bulk expenses) for both solar water heaters and solar PV interventions combined within 10 years.

In order to avoid this potentially crippling impact on city revenues, changes to the current modus operandi will need to be planned for and implemented over the next 5 years.

The graph also indicates the revenue impact if households with solar PV systems are charged a fixed charge and separate energy charge, as with Cape Town's new residential net metering tariff of R9,83/day fixed charge and 91,69c/kWh energy charge. Such a tariff is considered a reasonable approach, as net metered households need to pay for the grid availability even if they are generating most of their own energy (unless they choose to go off-grid completely of course). The graph shows that there is minimal revenue loss if such a fixed charge tariff is applied. However, such a tariff also discourages the adoption of solar PV significantly, as savings for the customer are much less than if they are charged the normal residential tariff. This is discussed later. It is important to note that such a net metering tariff may not avert a revenue crunch however, as households may well choose to still install solar PV and limit its generation to "own use" – i.e. not feed back into the grid at any time. It is questionable whether the city would be able to charge them a net metering tariff in this case, or would even know that they have a solar PV system installed. For the high-end household this is likely to become a financially viable choice in the next few years, and the revenue impacts for the city will be significant. The large-scale adoption of solar PV systems may therefore well take place irrespective of tariffs imposed – either "under the radar" or outside of the regulatory influence of government.

NERSA has made the point that there is no provision in the 2010 Integrated Resource Plan (IRP2010) for small solar PV or other generation within municipalities,

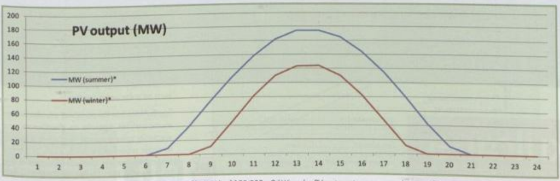

Fig. 2: Average generation profile (MW) of 100 000 x 2 kWp solar PV systems in summer and winter (Cape Town).

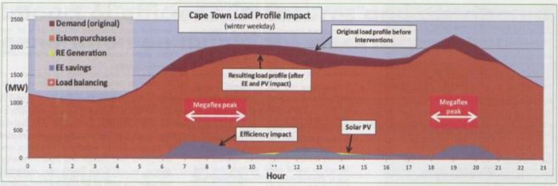

Fig. 3: Load profile impact modelling results for efficiency and solar PV interventions in Cape Town (winter weekday).

and that municipalities are not mandated to buy and sell power generated by such systems. However there is a reasonable amount of confusion around this issue, including potentially conflicting statements in other official documentation Such as the net metering guidelines for <100 kW systems issued by NERSA, which suggest that net metering can be undertaken by cities (Standard Conditions for Embedded Generation within Municipal Boundaries) and the fact that some cities are allowing net metering already. All considered, the significant future adoption of solar PV may well proceed despite the regulatory confusion and introduction of net metering tariffs.

Pressure on cross-subsidies for low-income electrification

In addition to the potential revenue impact of efficiency and solar PV interventions, there will be mounting pressure to increase cross subsidies for low income electricity provision. This is largely because of the escalating focus on electrification of informal settlements coupled with the high growth rates of these settlements [3].

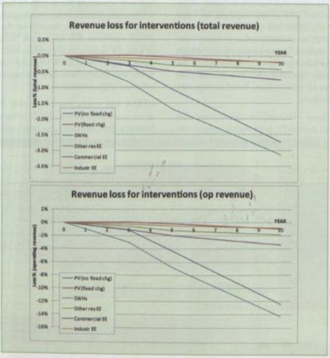

Fig. 4a and b: Revenue losses for solar water heater (SWH) and solar PV interventions.

Double whammy and death spiral

Cities are in an increasingly difficult position where they need to find the resources to cross-subsidise poor households, and this pressure is increasing as informal electrification becomes more of an obligation, yet electricity revenue is under strain as bulk prices increase and important surplus-generating hi-end customers look for ways of spending less. Cities are under fast increasing revenue stress from two sides – a "double whammy". If attempts are made to alleviate this pressure and sustain adequate revenue by further loading the tariff to wealthier residential and other customers (who currently are the key surplus income generators), this just accelerates their adoption of solar PV and efficiency options to reduce their electricity expenditure, which further reduces city revenue – a "death spiral" [5].

Continuing on the current path is therefore likely to be untenable and, and while there are longer term national government responses required to support cities in avoiding a revenue crisis and maintaining service delivery standards, municipalities may well need to initiate short term tariff changes to mitigate this looming business challenge.

Conclusion: issues, solutions and ideas

South Africa is being hit by a rapidly changing electricity sector financial situation due to fast rising national grid electricity prices that can't be readily absorbed by users, coinciding with rapidly decreasing costs of small solar PV, and global warming emissions pressures that accelerate energy efficiency implementation such as solar water heaters.

South Africa has the particular situation where municipalities operate as distributors and electricity sales generate revenue that is used to cross subsidise electricity costs in the low income market and feed into municipal coffers as a "hidden tax". On the one hand pricing has to buffer the poor from unmanageable

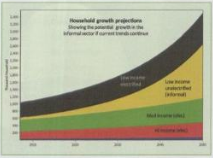

Fig. 5: Informal household growth rates are high, and servicing them will place an increasing burden on city finances.

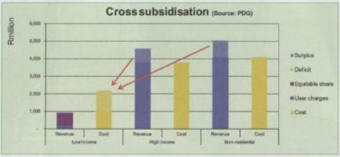

Fig. 6: Surpluses from hi-end residential customer electricity sales and from other customers cross-subsidise poor customers (illustrative) [4].

hardship, however, this can run the risk of pushing the price burden on the hi-end users into realms where alternatives become affordable and desirable and they withdraw from the system partially or fully – the double whammy and potential death spiral.

Current tariff systems will need to be reconsidered to respond to these challenges. Amongst other things, tariffs will need to:

- Not burden hi-end users excessively thereby driving them seek alternatives and reduce their contribution to revenue generation (the top IBT tariffs can unfortunately have this effect)
- Generate enough surplus to cross-subsidise low income households and contribute to other city services
- Ensure that net metering customers pay for grid availability in a fair manner (i.e. introduce a fixed cost component for their use of the distribution grid)

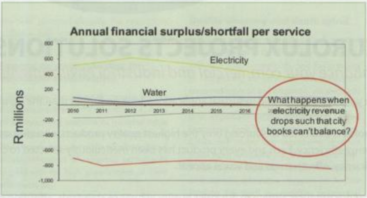

Fig. 7: Declining revenue from electricity sales is predicted if current trends continue (illustrative) [4].

Is it possible to balance these impacts in tariff design? This is uncertain. But current tariffs are unlikely to achieve this, and the inclining block tariff in particular needs to be flagged as potentially counterproductive in this regard.

What if revised tariff systems disincentivise customers from installing net-metered solar PV and solar water heaters through the introduction of bigger fixed charges? End users will have reduced financial savings as a result of tariffs with lower energy charges and higher fixed charges.

- Solar water heater or other efficient water heater implementation is recognised as being economically valuable for the country, and thus detrimental effects on such programmes needs to be avoided. This could be achieved through continued targeted national subsidies as with the current Eskom IDM programme.
- Solar PV net metering disincentives would be unfortunate as these are entirely customer-funded green electricity generators. But is it better to have these end users putting funds towards a solar PV system or supporting the city service delivery through revenue contributions? If the country needs more green generation, could it not be more economically sensible to focus on large-scale plant? Will thousands of small PV systems feeding into the grid create huge management problems for already over-stretched electricity departments? Given questions such as these, it seems unclear whether such a disincentive would be counter to national best interests. But it is clear that such net-metering customers need to pay a fair contribution to grid availability and operation costs.

However, household and commercial use of solar PV with no net metering (i.e. no grid feed-in) cannot easily be regulated by government, which creates a situation of generation capacity implementation that falls outside of public planning processes. The potential for such uptake appears significant, as discussed earlier, and trends in this regard may need to be monitored closely.

The main point this paper attempts to highlight is that there are growing pressures on municipal electricity revenue, and there is evidence that current electricity and PV price trends and tariff systems may rapidly lead to a death spiral – where key revenue generating customer contributions dwindle, and cities are increasingly unable to support poor households and general service delivery standards drop. It seems appropriate that a plan is put in place urgently to address this situation.

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Contact M Bouchers, Sustainable, Energy Africa, Tel 021 702-3622, info@sustainable.org

Simulation studies required for renewable energy integration

by Vimeshan Pillay, Geeven V Moodley, and Dr. Glenn D Jennings, DigSilent Buyisa

Renewable energy (RE) facilities need to conduct compliance studies, in order to prove that their facility has the necessary capability in order to meet the currently published grid code, as well as to ensure that the farm does not contravene the existing NRS and other published standards.

These studies, though not limited to, are:

- Reactive power capability
- Loadflow analysis
- Losses
- Short circuit/fault level contributions of RE generators
- Power quality – harmonics and flicker

Dynamic simulations including low voltage ride through capability and determining accurate fault levels will also be required (after successful bid notification).

Voltage/reactive power requirements

Reactive power capability

Voltage regulation is essential to ensure correct operation of all connected loads; therefore control of reactive power at the point of common coupling (PCC) is required in order to ensure the network voltage is regulated within specified limits. Voltage regulation requirements are defined by the network owner, utility or municipality. The grid code [1] requires the farm to be able to operate at leading and lagging power factor of 0,95 for farms larger than 20 MW and 0,975 for farms smaller than 20 MW.

Accurate fault level and network impedance at the PCC as well farm layout and generator reactive power capability curves are required to evaluate these criteria. It is important to note that the grid code specifies requirements at the PCC and manufacturers specify reactive power capability at the generator terminal. This makes knowledge of the farm layout critical to account for the reactive power consumption within the farm.

Network voltage profiles and loading

Due to the variability of the output of RE generation and further taking into account the variability of network loading, you cannot evaluate the farm at a single operating point. Network voltage profiles and loading should be evaluated for at least the following operating points. Generation refers to the farm output:

- High generation + high network load
- Low generation + low network load
- High generation + low network load
- Low generation + high network load

Additionally contingency analysis of the network should be done for each of the above mentioned operating points.

Rapid voltage change (RVC)

In line with NRS 048-4 [2], if a farm is to be totally disconnected from the network the voltage at the PCC pre- and post-disconnection must not change by a specified percentage. This percentage is dependent on the repetition rate of changes in a period of time and the voltage level at the PCC as described in NRS 048-4 Table A5 [2].

In the event of non-compliance the following options are available:

- Change the farm operating power factor.
- Reduce the farm active power output (this is not ideal as to the objective of farms is to sell as much power as possible).
- Consider increasing the fault level at the PCC. It is important to discuss with the network provider future upgrade plans to the network that may increase the fault at the PCC.

Ideally the farm should operate at unity power point power factor with maximum output but if the RVC criteria require you to change the operating level at the PCC, it is imperative that the network provider is informed accordingly.

Losses

Electrical networks are designed and optimised to transport electricity through HV systems and distribute it through the MV/LV systems. RE farms connected to the MV/LV systems may cause increased losses depending on the operating scenario. Hence network losses must be evaluated for the four main operating points.

Losses within the farm result from long internal cables (up to 10 to 12 km in some cases) and transformer impedances. Typically the farm design would aim to keep the farm losses below 2%.

Short circuit/fault level analysis

When considering RE farms, classical short circuit methods based on steady state analysis are not always accurate for the following reasons:

- Controllers (power electronic converters) are fast enough to control short circuit currents from the first milliseconds and cannot be considered in the steady state calculations.
- Highly non-linear behaviour due to special protection mechanisms (crow-bar, chopper resistance, etc.).

Classical short circuit calculation methods provide acceptable results when verifying the short circuit levels of existing or new installations (e.g. verify short-circuit level, circuit-breaker capacity, sizing, etc.).

When accurate results are required a time-domain simulation should be used (e.g. analysis of protection relay mal-operation, sizing of associated power electronic devices, development and test of control concepts, etc.).

Accurate time domain simulations require detailed controller models which must be sourced from the manufacturer.

Power quality

Harmonics

Harmonics or harmonic distortions are a function of the PCC location. Hence even a small contribution from the farm that is connected to the network at a point which is susceptible to harmonics issues can have huge implications to the network. This suggests that an accurate network representation is needed when conducting power quality studies. Compatibility levels for harmonic distortion for electrical network are stipulated in NRS 048-4 Table A1 [2].

Flicker

As mentioned with harmonics, flicker analysis in also network dependent and the location of the RE farm plays a major role in the outcome of the analysis. Compatibility levels for both long term and short term flicker for connection to an electrical network are stipulated in NRS 048-4 Table A4 [2] for the various voltage levels at the PCC.

Low voltage ride through

One of the requirements in the grid code specifies the required capability of a farm to "ride through" a low voltage at the PCC. Critically it states that post fault the voltage at the PCC is allowed to be at zero for not more than 150 ms and should recover to at least 0,85 p.u. within 2 s. According to compliance test standard for wind [3], low voltage ride through compliance is only required to be shown prior to the farm commissioning and connection. As with the short circuit/fault level analysis any time domain simulations require accurate controller models which must be sourced from the manufacturer.

Protection

RE farm protection is set based on the fault levels calculated by the utility/municipality/network provider. These fault levels must be checked thoroughly to establish the following criteria:

- For what operating condition was this calculated (network topology, generating pattern)?
- What calculation method was used to achieve the value (planning criteria or operational criteria)?
- Is this maximum or minimum value? (You need both to set protection).

Network protection must further consider:

- Reverse power flow
- Accurate fault level contributions from farm (dynamic simulations including detailed controller models)
- Accurate breaker rupturing capacities

Subsynchronous control instability

Interconnection studies for any generator or power electronic equipment in the vicinity of a series capacitor should account for system configurations that can give rise to subsynchronous oscillations. Subsynchronous resonance (SSR) or subsynchronous control instability can occur when wind farms are connected to networks with series capacitor compensation. The "Cape" network has traditionally been a SSR susceptible network with its series compensated lines.

Conclusion

Steady state simulations together with power quality analysis should be conducted upfront and this will give the network provider and the developer a worthy idea on the impact of the RE farm on the network. Besides the wide range of studies that need to be conducted further aspects such as variances in the network topology, loading, generating patterns in the network also need to be considered, in order to fully assess the impact of the farm on the network and vice versa. Detailed dynamic studies are required prior to commissioning and connection and the results must be presented as part of the connection procedure.

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Contact Vimeshan Pillay, DigSilent,
Tel 011 512-0100, vimeshan@digsilent.co.za

Demystifying the smart grid

by Stuart Michie, ABB

The principles of the technology of today's power grids have not changed significantly in the past 100 years. Electricity is a product that has to be generated at the time of need. The level of power generation is set to match the instantaneous demand. With the constraints in power resources, this has to change, hence the development of the smart grid.

This paper investigates some of the concepts around the idea of the smart grid, with the purpose of showing that implementing a smart grid is not the application of a single technology, but the collective result of a system design with the application of many technologies and products. It is important that a utility takes a holistic view of individual smart grid related projects in order to get the many components to work together and achieve better utilisation on capital spent.

Vision of the smart grid

Around the world, and in South Africa, it has become evident that utilities need to do more with less. Constrained power availability, rising demand, environmental pressures, cost pressures, skill shortages and limited resources have all led to increasing pressure on the power grid.

The digital age has placed increased demands on the quality of supply, while new alternative sources of generation have made the reliability of supply more unpredictable. The configuration of the power grid is changing from having centralised generation (Fig. 1) with one-way power flow to end-consumers to having distributed power generation and consumption (Fig. 2). No longer can the assumption be made by a consumer that the power grid is an infinite source of energy that can be tapped at will.

To successfully operate a power system under these conditions a clear real time picture of the status of the system is needed. Better utilisation needs to be made of existing assets. More intelligent investment decisions need to be made. Knowing the real time status of the elements of the power grid are key to achieving this. Integrating the realms of operational technology and information technology is essential to realise the vision of the smart grid. The key concept is integration.

Technology

Operational technology

Operational technologies are the systems and devices that allow the physical monitoring of a power system, such as basic SCADA, RTUs, protection relays, meters and communications. Operational technologies provide the measurements, indications and control interfaces to physical plant in the power system. The more detailed information provided, the better a power system can be modelled and controlled.

Information technology

Information technologies are the enterprise software systems that enable the management and operation of a power system. Examples of information technology systems are outage management, distribution management, asset management and advanced SCADA (Fig. 3).

Integration of the operational technology world and the Information Technology world brings significant benefits to a utility.

As an example, a sophisticated outage management system can exchange information with a SCADA system, a geographical information system, a metering system, a customer management system, a crew management system and a call centre to provide a dynamic, real time fault and planned outage management for a utility.

Systems thinking

When planning an investment in a technology, it is advisable to take a "systems view" approach. For example, installing an automatic meter reading system (AMR) to manage payment and customer connections provides useful functionality. Broadening the scope to an advanced metering infrastructure (AMI) with two way communications provides more possibilities for smart grid integration and associated benefits.

Making the meter information available from the AMI system to provide customer outage information to an outage management system increases the value of the investment.

This requires the correct specification up front to realise these synergies (e.g. meters report outages within a short time period rather than only reporting metering data once a day). Using the same system to feedback information to consumers adds another benefit, while using the same infrastructure.

Four key areas

There are four key areas that must be considered to implement the smart grid

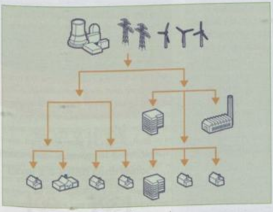

Fig. 1: Traditional power grid.

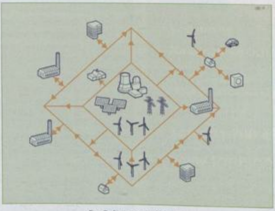

Fig. 2: Power grid of the future.

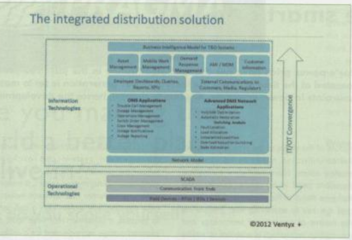

Fig. 3: Integration of operational and information technology.

Communications

Communications is key for enabling the smart grid. Without a reliable, all-reaching communication network, it will not be possible to realise the full benefits of the smart grid. Our daily lives are being improved by the continuous improvement in mobile communication technologies, which are enabling whole new applications such as live traffic enabled GPS and personal instant messaging. The same is needed to enable the smart grid, with the ideal being to have two-way communication enabled right to the end devices in each consumer's installation.

There is no one size fits all communications solution. Different technologies are applied to the core network, the distribution area network, the neighbourhood area network (NAN) and the home area network (HAN) (Fig. 5).

New technologies are being developed and existing technologies are being improved in ways that allow the implementation of communications for the smart grid. For the backbone there are the existing multiplexer type network technologies (SDH, PDH) using fibre optic and microwave radio. For the NAN there are wireless mesh technologies that create a self-configuring and healing network. For the last mile there is power line carrier (PLC) and for the HAN, short range radio technologies such as Zigbee and Bluetooth

At the medium voltage level, a good communications network supports the implementation of distribution automation. Two way communications with end customers gives better control of power system demand and the ability to match demand to available generation. Good communications infrastructure also enables real time customer engagement for outage management. It is far better to be able to inform a customer that calls in to report a fault that the fault is known and when the estimated restoration time will be.

Distribution automation

The second key to the smart grid is distribution automation. Monitoring and automation of high and medium voltage plant allows better management and control of the power system plant, thereby leading to better reliability and better efficiency. Outages are detected quickly and can be dealt in a shorter time, thereby reducing customer minutes lost.

Traditionally SCADA monitoring has been applied at the HV to MV substation level. Today equipment is readily available to extend monitoring down to the secondary distribution level, greatly extending the reach of monitoring to make distribution automation possible.

The provision of fault current measurements and earth fault indicator operation leads to the possibility to have a self-healing grid. Dynamic algorithms in the SCADA system can sense when a fault has happened and, based on real time loading and back feeding capabilities, devise and, optionally, execute a switching plan to restore supply to as many customers as possible.

Loss reduction through Volt-var control is another benefit of distribution automation. Best suited to rural networks, algorithms on a SCADA system can be used to manage capacitor switching on medium or high voltage networks to control the var flow, which in turn manages the voltage profile and the losses.

Grid analysis

Improving the operations of power networks can be achieved using several tools in the information technology world to analyse the history. From an outage management system, fault causes, durations and other statistics for performance measurement can be derived automatically. This provides better information that automatically leads to improved reporting quality to the regulator and the ability to manage future events better. From an asset management system, non-operational data can be used to track the health of assets for condition based maintenance. This leads to better performance of assets and reduced maintenance costs. Scarce skills can be utilised more effectively.

Integrating new technology

Integration of new technology is the final key area of the smart grid. While these might not be prevalent in South Africa yet, they will come as demand from customers grows. When they arrive, electric vehicles will place significant new demands on power distribution infrastructure. This needs to be managed in real time, such as with real time pricing of electricity to manage the demand for charging. Electric vehicles can also be used as a source of storage for utilities, where power can be bought back from customers to assist with meeting demand at peak times.

Interconnection of renewables, such as wind and solar, will bring a new dynamic to the power system. These are variable sources of power that are not predictable. Consumers will also become producers with the management of distributed generation requiring incorporation into power system. Local area power storage is another new technology being explored. Power is stored in a medium voltage network using a storage facility such as a battery bank. This is used to bridge short term variations between demand and supply and helps reduce the effect of intermittent renewables.

Advanced meter infrastructure

While the main purpose of an automatic meter reading system is the management of billing and payment for electricity, there are many other benefits that can be derived from installing an advanced metering infrastructure (AMI). Using two-way communications systems, these systems can be used to provide useful information for other systems that make up the smart grid. Real time information can be used by an outage management system to provide indication of power outages and restoration. Before a customer is even aware of a fault, it can be identified and even repaired, with a corresponding improvement in the regulator measured indices. Power quality information can be provided by an AMI system. This information can be used to identify problem areas and initiate corrective action.

Advice of Change of Ownership of Tank Industries (Pty) Ltd

To Valued Stakeholders

We are pleased to advise that Tank Industries (Pty) Ltd was officially acquired by the Reunert Group on 1 April 2012. The sale was concluded 1 June 2012.

The Reunert Group was established in 1888 and first listed on the JSE in 1948. Reunert Limited is a leading South African company. The group operates mainly in South Africa with minor operations situated in Australia, Lesotho, USA and Zimbabwe.

CBi electric: african cables has been designing and manufacturing a comprehensive range of electrical power cables at their factory in Vereeniging, near Johannesburg, since 1935. Growth of the manufacturing facility has been consistent with the demand for the product locally while technological advancement has remained abreast of international trends. Today the company employs over 600 people and can justifiably claim to be a forerunner in the South African cable industry.

Tank Industries for over 25 years, have manufactured and distributed a wide range of quality connectivity solutions to the power, telecommunications and electronics markets.

CBI-electric: african cables and Tank Industries are two highly respected local manufacturers of cable and cable accessories supplying into the South African, African and International markets. Tank Industries will operate within the subsidiary CBi electric: african cables.

The acquisition of Tank Industries brings a full range of high quality, SABS, UL, IEC, ITC cable connectivity solutions into the CBI-electric: african cables fold. CBi electric: african cables and Tank Industries together are now able to provide a complete product offering when it comes to any cable installation whether it is electrical power, telecommunications or fibre optics.

Although the ownership of Tank Industries will change, the brand will remain the same. Tank Industries will continue to serve you under Tank Industries (A Division of ATC (Pty) Ltd)

CBi electric: african cables is committed to maintain current operations and to invest in the business going forward to ensure that we can continue to grow the business and serve our valued customers with the quality range of products and services that our customers have been accustomed to.

Please continue to address enquiries and business transactions to the usual account representatives.

Please contact Adriaan Theron, Tank Industries or Alan Dickson, CBi electric: african cables. Visit our websites. www.tank.co.za or www.cbi-electric.com

Demand response control is another possible benefit of AMI. With the scarcity of generation resources and the growth of intermittent renewable sources, no longer is the power system a seemingly infinite source of energy. Therefore demand has to be dynamically tailored to meet supply constraints. An AMI system can be used to control consumer loads, either by involuntary disconnection or by indication to the consumer to initiate voluntary disconnection of loads.

Benefits of the smart grid

What are the benefits of the smart grid? Why should a power utility implement the previously mentioned technologies?

Capacity requirements

Demand for power continues to grow. New loads such as data centres and the continuing electrification programme are adding more load to the power system. Electrification has the worst demand profile as it contributes to the evening peak. Demand management can be used to manage this peak and reduce the requirement for new generation, saving on capital spending investment.

Reliability

Distribution automation and the self-healing network make the power network more reliable. Outage management systems lead to a reduction of customer outage minutes due to automated fault location and fault process management. This not only helps a utility meet the regulatory requirements, but also gives consumers a more reliable supply and a better experience.

Asset management helps a utility to maximise the use of its assets. One of the benefits is that maintenance is done when required, making best use of scarce maintenance resources, while at the same time extending the life of an ageing power system.

Efficiency

The smart grid leads to better efficiencies, both on the power system and the use of resources. With ageing workforces and reduction of skills, it is required that the skills that are available to a utility are used more efficiently. Better management of faults on the grid and intelligent asset maintenance helps to achieve these efficiencies.

Dynamic power system optimisation reduces losses, gives better utilisation of equipment. Improved customer awareness increases efficiency as customers make better use of the power available to them.

Sustainability

For the power grid to be sustained in the future, the new technologies for generation will have to be successfully integrated. Interconnection of renewables into the grid while reducing CO_2 emissions, is crucial to sustainability of the power grid in the future.

The smart grid will assist in meeting the challenges of the integration of renewables.

Customer enablement

Improvement in customer education and awareness through dynamic feedback of information is a large benefit of the smart grid. AMI systems enable customers to manage their loads more effectively, with better understanding of the various loads that they have.

Outage management enables a vast improvement in the utility response to customer calls, allowing call centres to provide useful information to callers. Customer involvement in the power system operation removes the mystery of power. It is much easier to keep a customer happy that is informed.

Barriers

Deploying the technology needed for a smart grid is not a simple exercise. There are several barriers to its implementation.

Policy and regulation

The smart grid is a tool that can be used to implement government policies around energy usage. Timeous implementation of policies that deal with energy efficiency and usage are crucial to the implementation of the smart grid. In South Africa, energy saving is something that is high on government's agenda. This supports smart grid investment decisions that will improve the efficiency of energy usage and reduce overall demand.

Market uncertainty

A second barrier to the implementation of the smart grid is the financial disincentive to power utilities. Smart grid technology can be expensive and, at the same, reduces a utility's revenue stream due to the reduction in use of energy. The world economic crisis has also limited the amount of money available for

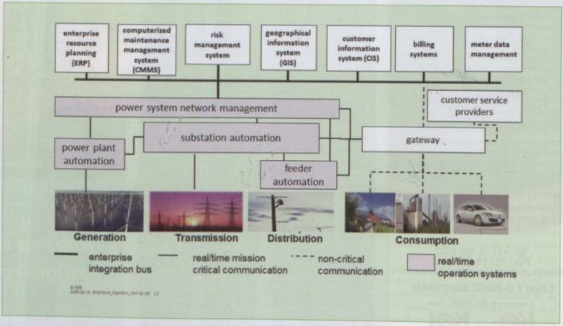

Fig. 4: Integration of utility systems.

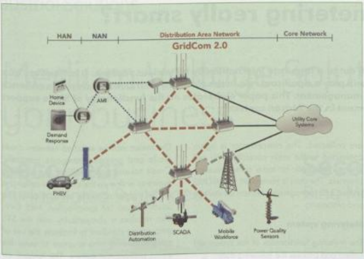

Fig. 5: The evolving grid – new intelligence.

smart grid projects, thereby adding a barrier to implementation.

Technology barriers

While there is smart grid technology that has been in the market for many years, such as SCADA and substation automation, there is significant development effort that is on-going to bring new technology to market and to better integrate existing technologies. New technology requires implementation and testing to become proven technology. Smart grid systems can be complicated and not all solutions have been fully developed, so it is in a utility's best interest to select a proven technology partner that has the track record and experience to make systems work.

Security

As systems within a power utility begin to communicate, the issue of security is raised. Smart grid solutions should be designed with appropriate security built into the system from the outset, rather than being bolted on later.

Lack of consumer involvement

Customer involvement is vital to the goal of managing power demand. Education, real time information with regard to pricing and live feedback of power system status are tools that are provided by the smart grid to get customers involved in managing the process of using energy more efficiently.

Until customers can see this kind of information, the assumption remains that, because the lights are on, there is no problem. This is a barrier to achieving the goals of efficient energy usage and matching demand to supply.

Standardisation

As with all new technologies, when new products are developed they start off being proprietary. This is due to standards often not being available to match the new technology developed. It is in power utilities' best interests to demand standardisation. This is so that utilities are not locked into single vendor solutions, but are able to mix and match equipment to provide a suitable overall system solution.

Standards bodies such as the IEC and IEEE are in the process of developing standards for the smart grid (see www.iec.ch/smartgrid). In the SCADA and substation automation worlds, IEC standards have long been in place and utilities are reaping the benefits of standardised solutions.

Conclusion

Implementing a smart grid is not a one time project but rather a transformation process. It is a journey that will be undertaken by any utility that will take time. Many of the components are available and in use today.

There are many areas to consider. Utilities must take into account their business needs and determine what overall outcome is required before selecting the right combination of technology to provide the correct solution.

Making the grid smarter will require coordination across the different disciplines within a utility to see the benefits of a truly integrated set of systems

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Contact S Michie, ABB, Tel 010 202-5947, stuart.michie@za.abb.com

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that this was implemented half way through a project, it was decided that a change in routes would be detrimental to the project. On new projects this cost saving will also be realised. A huge saving on handheld equipment is also possible as cellphones can be used in the place of this high cost item and is done so very successfully on this project. The cost of the handheld units was already incurred as part of this project and therefore no saving on this was achieved. A further 10% saving can be achieved if cellphones are used as handheld equipment.

Conclusion

The use of electronic infield data collection solutions are proven to return not just improved data, but to also have cost savings as a result. It will revolutionise the way in which engineers will manage maintenance teams and the way finance departments will do meter reading and credit control. It will improve service levels to the public.

With the age of smart meters on our doorsteps, the quest for accurate data is even more important as visits to meters will become fewer and the chances to collect or correct data from the field will be reduced. Data collected during the process of installation of smart meters must be accurate or it might stay incorrect forever.

Mobile technology and electronic data collection systems are widely used in the private sector and is the way of the future for municipalities.

Contact Hugo Gotze, Motla Metering,
Tel 012 663-1328, hugog@motla.co.za

When is smart metering really smart?

by Kobus van den Berg, Aurecon

Smart metering (SM) systems are rolled out at a high rate internationally for various reasons. It is however true that SM as a component of smart grids will play a significant role in the electricity distribution industry to enhance energy efficiency and support revenue management. This paper elaborates on the functionality of SM to support various aspects of distribution management in the African context.

Smart metering for the purpose of this presentation comprises a metering/ monitoring/load switching device located at the electricity supply point to a customer premise (Fig. 1). The devices will also enable utilities to perform much more than merely obtaining a consumption reading for billing purposes. The device and its supporting infrastructure enable utilities to effectively monitor and manage the low voltage distribution system in a network. This part of the distribution network has always been the "neglected" part of an electricity supply system due to the cost of installing SCADA (supervisory control and data acquisition) systems at this level in the system. Any feedback from this part of the network was accomplished by customer feedback and complaints as well as maintenance and meter auditing operations. Thus in most cases this is a reactive process.

SM is installed internationally for various reasons and it is important to understand what the African requirements are. The following functional and management functions can be supported with appropriate technology:

- Energy efficiency
- Demand management
- Maintenance management
- Revenue management
- Revenue protection
- Network management

It is also necessary to future proof systems as much as possible to extend the lifespan as well as improve the financial viability by:

- Adopting proven international standards
- Appointing reliable meter system suppliers
- Exploiting the advantages of the new metering system by effective integration into existing systems and processes.

This paper will thus attempt to explain the total impact of installing SM systems as a path to upgrading and improving network and utility management. A typical SM system will include functional blocks as shown in Fig. 2. At the customer premise a smart meter with load switch and in-house display will be installed. These devices communicate with concentrators via radio or PLC (power line communication) communication systems where the data for a group of meters are collected. The concentrator is again connected to the main controllers via cell phone, fibre optic or radio communication channels. The data is transferred to a MDMS (meter data management system) for storage and processing.

Metering system

The metering functionality of the system will collect and process the following data:

- Automated readings
- Interval data
- Support complex tariffs
- Credit/prepayment switching
- Automated prepayment credit token transfer

In the metering mode these systems provide the measurement and recording functions to enable effective measurement of consumption data for billing purposes. The fact that it records interval data enables the utility to determine when and where energy has been used. Half an hour profile data can be obtained to facilitate network management and enables the use of time of use tariffs.

The system will thus enable the utility to record consumption accurately as well as have access to detailed energy flow information in terms of the load profile data recorded every 30 min. Readings on all meters will be synchronised to enable detailed consumption information during a specific period and facilitate energy balancing in a specific area of supply.

The meters can be switched between credit mode and prepayment mode remotely. Credit tokens purchased at the vending outlets or online via the internet or cellphone will be transferred to the meter directly. The South African SM specification, NRS 049, also requires a compatibility with the STS prepayment standard to facilitate the use of existing vending infra-structure to serve the smart prepayment meters. The keypad on the customer interface unit (CIU, display and keyboard installed in a customer's residence) will also allow the manual entry of STS tokens when required.

The meter allows the implementation of complex tariffs. The use of TOU (time of use) tariffs allows the utility to offer new energy products to the customers as well a use pricing signals to manipulate the consumption pattern of consumers to enhance energy efficiency. The SM system will support improved meter readings and billing processes. Fig. 3 depicts the flow of data to the various functional applications.

The smartness thus provides a flexible, multifunction metering system to enhance the management of distribution systems and improve energy efficiency.

Revenue management system

- Accurate meter readings
- Timeous billing
- Pre-processed readings with VEE (validation, estimation and editing)
- Remote connect/ disconnect

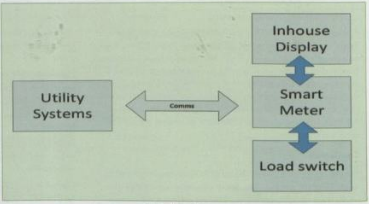

Fig. 1: Basic SM system.

One of the most important challenges in South Africa is to read meters and produce accurate bills to enable customers to pay their dues. Meter readers are used to physically visit customer premise to read meters. It is not always possible to get access to meters resulting in "no reads" or "estimated" readings on a customer bill. Many fairly manual processes are followed to verify meter readings and bills. It is however not possible to check every single bill in detail on a monthly basis. In the case of SM the consumption data will however be validated and any inconsistencies corrected in the MDMS before it reaches the billing system, ensuring much higher quality billing. The VEE (validation, estimation and editing) functions allow the utility to effectively manage consumption levels, missing readings due to meter failure and energy theft due to bypassing of meters. The occurrence of incorrect billing will be reduced significantly.

The SM system supports functionalities like remote connection/disconnection. It will facilitate timeous and accurate billing to ensure that customers receive correct bills. If the customer does not pay his/her bill a message can be sent to the CIU warning that payments are due. If no reaction from the customer occurs, the supply can be switched of remotely. As soon as payment takes place the supply can be restored immediately. It thus improves the revenue collection process significantly by eliminating physical visits to the customer premise. The communication link to the meter thus provides the utility with the same control mechanisms as used by cell phone and telephone service companies.

Accurate meter reading and billing will restore customer confidence in the utility and improved payment will result.

The smartness thus provides timeous, accurate readings and billing to improve customer confidence as well as management mechanisms to improve revenue collection.

RP (revenue protection) system

- Reading VEE will detect anomalies
- Tamper detection
- Alarm generation
- Energy balancing and loss detection
- Non-payment/tamper disconnection

Most utilities employ RP officials or contract meter auditors to visit and inspect meter installations for safety and especially tampering issues. One often encounters reports of significant improvement in payment after the meter audit and claims of reduced losses. This process is fine but very time consuming. The visibility of the meter auditors also motivate customers not to tamper with meters. The main challenge is however the time and cost to maintain this visibility where required. Soon after the meter audit, customers revert back to their old tampering habits or pay "contractors" to "adjust" their metering system.

A utility requires RP officials to be at the right place at the right time. SM systems can be this "guard dog" to monitor meters 24/7. Any tampering with a meter will generate an alarm that will be forwarded to the utility MDMS (meter data management system). The VEE functionality will raise an alarm of suspicious consumption levels. Daily reports will guide the RP official to attend to immediate problems and provide a focussed, enhanced more cost effective service to the utility. The remote disconnection function can be utilised to manage tampering and non-payment cases. This will result in reduced energy losses, less tampering and more efficient personnel and supporting resource utilisation.

The smartness thus provides improved, less costly revenue protection operations with automated meter monitoring and alarm functionality. The end result will be significant reduction in energy losses.

Network management system

- Low voltage SCADA
- Outage detection and management
- Demand and load control

Distribution utilities hardly ever deploy SCADA or monitoring systems at the low voltage level. This is mainly due to the cost of such systems. The installation of SM however requires a communication system covering the low voltage network. The meters effectively constitute a SCADA RTU (remote terminal unit), albeit with limited functionality, at the supply point and SM can also be installed at the 11 kV/400 V transformers. The SM system does not provide real-time information with the latency of a SCADA system but nevertheless provides useful information regarding the state of power at the supply point. Any failure of power will be reported and the meter stores "event" information that can be downloaded. Power quality information is also available. The SM is thus a vital component in the development of SG (smart grids).

The SM also provides load switches to control loads on the customer side of the supply point. Geysers, pool pumps and air conditioning can be included in an effective demand side management system enabling the network control centre to manage demand in critical supply situations.

The smartness thus provides a low voltage network monitoring system with demand side management capabilities.

PQ monitoring system

- Basic PQ monitoring at LV supply points
- Voltage and interruption logging

The SM provides basic power quality monitoring at the customer supply points. This facility has never been available to utilities on the low voltage network. The only method to solve this was to use recording equipment or dedicated PQ monitoring equipment at strategic points in a network. If a customer for example complained about the voltage level, a specialised investigation had to be performed. This information is now available and high and low alarms can for example be set to record the problem periods.

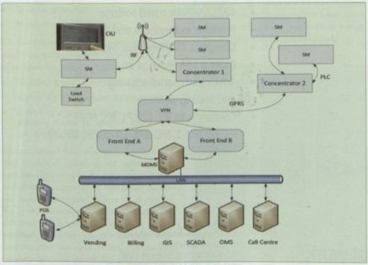

Fig. 2: SM system.

The smartness thus provides a distributed low voltage network power quality monitoring system with threshold alarm capabilities.

Maintenance and planning system

- Distribution system loading and power flow
- Faultlog system
- PQ information
- System loss measurement
- Parameter trending facilities
- Maintenance alert
- Job scheduling
- Meter error detection

Analysis of the data collected from SM system can be utilised to identify maintenance actions as well as network extension and upgrade planning. The PQ and power outage information will provide a good indicator where the network needs maintenance or upgrading. Meter failures can be detected immediately and the necessary maintenance and repair teams activated. These operations can now be focussed to use personnel and other resources more efficiently. Customer service will improve due to prompt reaction to failures in the distribution network.

If SM is used to monitor each low voltage substation as well as all the customers supplied from this point, energy balancing is an automated process. Loss measurements can be used to identify technical and non-technical losses. Capital and maintenance budgets can now be based on operational information from the SM systems rather than ad hoc measurements in the network.

This smartness thus provides low voltage network maintenance and support information

Customer information system

- Consumption feedback
- Cost and tariff information
- Outage warnings
- Bill payment information
- Remote disconnection/reconnection
- Prepayment options

The customer plays a vital role in the successful implementation of SM systems. As was the case in many other countries in the world, customers can either accept and utilise the SM facilities or view it as a method to "spy" on them and force them to pay for services. In many cases customers have taken the stance that the radio frequency emission of these metering systems is detrimental to their health (although everybody is using a cellphone with much higher RF emission) or in some other cases that the more detailed consumption information gathered is impeding on their privacy. Whatever the case may be, the customer should be convinced and educated to realise that the SM is providing essential and useful information.

It is thus essential that effective implementation of SM is to the advantage of the customer in terms of energy management as well as the improvement of services. The SM system opens a new communication channel to customers to inform them of the actions and intensions of the utility without reverting to call centres and the other media.

The direct information available to customers is consumption and cost feedback on the CIU. To ensure that a customer responds to energy efficient signals and improve energy efficiency, it is vital that customers be given the correct timeous information. It does not help too much if a TOU tariff is implemented and the customer only sees the result of his consumption pattern on a bill two weeks after the end of the consumption month. It is thus important to directly involve the customers in the roll out of systems to show that they can save costs by using system information.

Payment notices to the customer can be a very persuasive tool to manage revenue collection. (Everybody reacts very quickly to the DSTV mail message on the screen.)

The smartness thus provides the utility with a communication mechanism to keep the customer informed about energy consumption, cost as well as network operations.

Demand control system

- Direct control of devices like geysers, air conditioners and pool pumps
- Load limiting during high demand/supply shortage crisis situations
- Indirect load and energy efficiency control via TOU tariff structures

South Africa is also like many other African countries in a predicament that the demand for electricity is at times very close to or more than the supply capability of the generation system. Many energy efficiency and demand side management projects have been launched already. The SM system however provides two methodologies to manage the demand for electricity on the consumer side of the supply network. The first method is to provide load switching facilities that can be controlled by the utility. These switches can be utilised to disconnect the supply to non-critical appliances like air conditioners, pool pumps and hot water geysers as well as other residential loads. The metering systems can also be used to limit the supply to a customer and motivate the customer to disconnect load himself.

The second method to manage demand and promote energy efficiency is to use TOU (time of use) tariff structures to reflect the actual cost of energy at a particular moment and also send a strong price signal to the customer. By effectively using the TOU tariff a customer can reschedule certain loads and save electricity cost as well as improve energy efficiency. To implement SM without the advantages of TOU tariffs is essentially like a car without tyres, not very effective.

The smartness thus provides demand side management tools to control peak demand and improve energy efficiency.

Data management system

SM is about data management and the extraction of information gathered with the metering system in the low voltage network. As illustrated many benefits can be derived from the use of data in the SM system. The heart of the operation is however to install a system to manage the data, analyse data

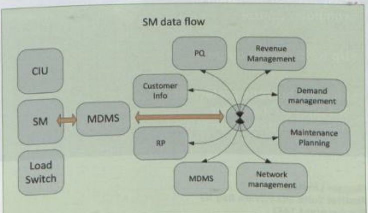

Fig. 3: SM data flow.

and convert this into useful management information. None of the abovementioned functionality is viable without a very effective MDMS (meter data management system.) Many utilities underestimate the impact of these components in a system and collect a massive amount of useless data. Some utilities view the MDMS as a store for SM data. Although data is stored in this system the conversion to information is a major task requiring specialised software and programming tools. The functionality of the MDMS is a presentation all by itself but includes the following items:

- Consumption data store
- Alarm processing
- Billing data pre-processing
- Installation data storage
- Tariff management
- PQ reporting
- VEE function
- Reporting and analysis
- Tamper reporting
- Energy balancing
- Unified interfacing to existing systems from multiple metering technologies
- Prepayment token management
- Planning and maintenance data input
- Power quality analysis
- GIS source data
- On demand reading processing

The smartness thus provides an MDMS to convert raw meter readings and related data into useful management and operational information.

Success factors to implement SM

- Be very specific as to what should be accomplished.
- Involve all role-players from engineering to finance.
- Do not under estimate the customer's role on the successful implementation.
- Adapt business process to maximise benefits to be derived from a SM system.
- Use only proven technology and standards.

Conclusion

- SM certainly has a place in African utilities.
- Utilities should exploit the full range of functionality of SM systems.
- Do not implement glorified metering systems.
- Carefully integrate SM into your distribution management systems and adapt business processes.
- Ensure that a specialised MDMS is implemented with the SM system to ensure that the collected data is effectively analysed and benefits derived from the total system.
- Remember SM is not a metering system but a new way of managing your distribution system more effectively.
- SM is only really smart if the collected data and related data from the systems are used effectively to improve and adapt business processes, utility operations, management and customer services.

Contact Kobus van den Berg, Aurecon, Tel 011 845-3734, kobus.sj.vandenberg@aurecongroup.com

Technology deployment as a smarter industry enabler

by Dr. Willie de Beer, SANEDI

The South African electricity distribution industry is confronted by numerous and significant challenges that impact directly on the sustainability of the industry and the ability to provide a reliable service to electricity customers. While the distribution grid served the country well in many aspects, the electricity grid is aging, outmoded, and stressed.

Due to the generation challenges which surfaced during 2007/08, the generation related requirements are currently receiving significant attention. The transmission infrastructure in general performs well and it is underpinned by a well-defined investment plan. The latest Eskom annual report confirms the performance of amongst others the transmission system as well as the distribution system. From these results it is clear that the distribution system requires urgent attention and this is equally applicable to the electricity distribution infrastructure under control of the municipalities.

All indications are that the electricity distribution operating environment will change significantly over the next couple of years. Most of the current distribution grid is not designed to accommodate for example; distributed generation, renewable solutions, or electric vehicles. This should however not be a surprise, since the current grid was not constructed with the 21st century power supply requirements in mind.

The availability of a more intelligent grid will not remove all the challenges associated with the electricity distribution industry. However it will enable the industry to better respond to situations such as when generation capacity constraints are experienced. At the sub-transmission level the current distribution industry in most cases do have an advanced level of grid intelligence and in some areas this is also applicable to the medium voltage networks/grid. However, there are no examples of advanced low voltage grid intelligence deployed to enhance customer service/interface, advanced customer communication or to enhance system operations.

Without investment in the infrastructure and the introduction of intelligence in the grid, the unreliability of the electricity supply will continue. Therefore without the desired interventions, the cost to the economy as well as to the end customers due to distribution related outages will continue. Furthermore the current grid is vulnerable to attack and natural disaster with limited "self-healing" capability.

The demand for electricity is projected to increase substantially towards 2030 and the cost to build new generation is increasing dramatically [1]. Electricity prices have increased drastically over the past couple of years and the approved tariff plan suggests that these increases will continue into the foreseeable future. Without addressing the grid intelligence i.e. making it smarter, it will become very difficult to match the grid reliability and availability with the projected economic growth targets. The current grid and technology deployed cannot support the projected economic growth or respond effectively to the broader dynamics affecting the grid. The inability to effectively introduce a demand response program is but one example.

South Africa has committed to substantial reduction of CO_2 emissions by 2035. To achieve this necessitates the integration of renewable energy into the electricity network/grid. It is important to note that the distribution grid, which includes the majority of the networks/grids operating at the 132 kV level and below, will be critical in the realisation of this objective. Without an advanced level of grid intelligence the introduction of renewable opportunities cannot be effectively pursued in the distribution sector.

Industry challenge

As stated, the electricity supply industry in South Africa is confronted with many challenges. Generation capacity shortage, poor performing distribution networks, ageing infrastructure, a significant infrastructure investment backlog, ageing workforce, inability to effectively introduce renewable energy options into the distribution grid and the inability to introduce effective demand response strategies are amongst the challenges facing South Africa. The increase

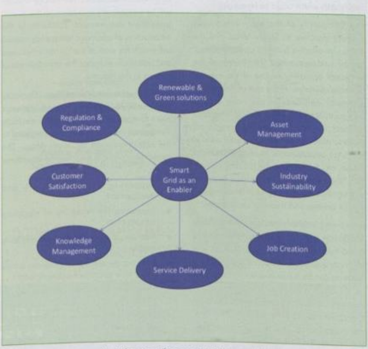

Fig. 1: Smarter grid as a smarter industry enabler.

in customer expectations, enhanced customer participation, introduction of distributed generation, the introduction of initiatives such as renewable energy options, the electric vehicle, etc. will change the electricity supply industry landscape and resource requirements significantly over the next five to ten years.

From a distribution perspective there are groups such as Eskom, some of the metros and some of the secondary municipalities that are in the process of addressing some of these challenges. However the larger population of the industry is not attending to these challenges. It is however important to note that where the interventions are taking place that they are not taking place within a national integrated framework.

This is however to be expected considering the structure of the electricity supply industry in South Africa and the lack of appetite to effectively reform the industry. The result is that there is a real risk that the investments might not be optimally leveraged or yield the expected results. Furthermore the risk of technology dumping and ultimately technology deployment without the required inter-operability is on the increase. In many cases procurement policies are also not geared towards the effective deployment of resources and investment in the infrastructure. The amount of uninvested money annually returned, in particular in the municipal sector, serves as an example. The good news is however that there is funding available within the industry which could be leveraged.

The complexity of the electricity supply industry structure in South Africa and the impact on effective business operations must not be underestimated. Neither must the inefficient operating regime of the industry be underestimated. At the root of the industry structural inefficiencies you have aspects such as dual regulation, a vertical integrated business competing with third tier government utilities, absence of clearly defined market rules, an unsustainable municipal financial model, etc. Furthermore the industry is driven by a "short term focus" while taking decisions with significant direct long term infrastructure, service delivery and resource implications.

Considering the challenges facing the electricity distribution industry, it is not reasonable to expect that the current practice of "milking" the electricity business to support other municipal functions can be a sustainable model. It must be extremely difficult to effectively run an electricity distribution business with a "balance sheet" that can barely support the "bulk electricity purchase and the human resource bill" i.e. after the "shareholder cut". While the principle of allowing a shareholder to derive a return on their investment is not disputed, there is a need for an urgent review of the current municipal funding model.

It is widely accepted that the average age of the electricity distribution industry infrastructure in South Africa is approximately 45 years. Furthermore the estimated R35-billion [2] in respect of the distribution industry infrastructure investment backlog is also in general accepted. Therefore it is reasonable to expect that South Africa is three to five years away from unprecedented distribution infrastructure failures. However, the question remains whether we are waiting for "I told you so" or whether the industry leadership will own up to the challenge and do something about it before it is too late.

Industry opportunity

The current electricity distribution grid was not constructed with the 21st century power supply challenges in mind. The need to address the 21st century power supply challenges and the urgent distribution infrastructure investment requirements presents a significant opportunity for South Africa. Over the past decade or so significant progress was made in many parts of the world in respect of technology development and the effective deployment thereof. While South Africa is confronted with substantial infrastructure investment requirements and resource shortages, it is now the opportune time to pursue advanced technology solutions. The incremental investment requirement to introduce advanced technology options will be insignificant in relation to the overall investment requirement. Furthermore the introduction of advanced technology options will enrich the work of the current employees and potentially enhance the attractiveness of careers in this industry.

The Energy Security Master Plan – Electricity, 2007 – 2025, provides a good reference point to evaluate the ability of the electricity distribution industry to effectively respond to the objectives/goals for South Africa: The master plan presents the following objectives/goals:

- Supporting economic growth and development
- Improving the reliability of electricity infrastructure
- Providing a reasonably priced electricity supply
- Ensuring the security of electricity supply as set by a security of supply standard
- Diversifying the primary energy sources of electricity
- Meeting the renewable energy targets as set in the EWP
- Increasing access to affordable energy services
- Reducing energy usage through energy efficiency interventions
- Accelerating household universal access to electricity
- Clarifying some of the policy issues in the context of an evolving electricity sector

The introduction of smarter grid technologies/ grid modernisation can provide the answer to some of the abovementioned opportunities/ objectives. Smarter grid deployment will also directly contribute amongst others to the realisation of the energy security goals and objectives as set out in the National Energy Act, 2008 (No. 34 of 2008).

Technology as a smarter industry enabler

It is essential that the electricity distribution industry grid must become smarter. A smarter grid will lead towards a smarter industry which will in turn directly contribute towards job enrichment and a reduction in operating costs. While the transmission grid in South Africa can be regarded as "relatively smart" the distribution industry has a long way to go. This is in particular true for the lower voltage networks within the distribution industry. It is therefore argued that South Africa should follow a structured approach towards the implementation of smart grid solutions. The South African Smart Grid Initiative (SASGI) is a vehicle which could be used to realise this objective in the interest of South Africa and the electricity distribution industry. The diagram in Fig. 1 presents an indicative picture of how smart grids can be used as an enabler to enhance the efficiency of the current electricity distribution industry.

At its core smarter grids are a sophisticated information system that would allow grid operators much greater visibility into the complex inner workings of the grid and achieving wide-area situational awareness. The same information system would provide customers with amongst others a window into their own energy use, giving them the tools to make better choices that align with their own values and needs. On the other hand it will assist the industry to achieve greater operational efficiency. Through a new paradigm of involving consumers with interactive loads that respond to the overall needs of the grid, the power providers and the power users work together to create the best possible electric grid at the least cost to the economy and the least impact on the environment. Data flow and information management is therefore central to the smarter grid. Considering the current grid status in South Africa it is envisaged that smarter grid options could be introduced in a phased manner i.e. a comprehensive smarter grid could evolve over a period of time. This approach would allow for the selection of the relevant enablers, which will best satisfy the specific needs of a utility and its customers.

A recent study conducted by Gridwise Alliance, an USA institute established by the industry alliance to provide direction in respect of smart grid development, provides some very profound insights. The study amongst others indicated that a reduction in overall energy demand has been demonstrated by:

- *Oklahoma Gas & Electric*: 1 to 2% through Volt/var control and 9% through demand response;
- *Pacific Gas & Electric*: 17% through the SmartRate program and 20% through energy efficiency programs.

Through distribution automation, Southern California Edison achieved, in respect of average customer minutes of interruption (CMI) per circuit, outage reduction duration of 33 minutes (47%). While there are numerous other projects at different stages of smart grid implementation, the overall improvement indicators are very positive. It is important to note that a smart grid is more than just a smart meter.

Conclusion

Smarter grids can be positioned as a business enabler as part of the customer interface, maintenance, refurbishments, strengthening and new network programmes. Relative to the distribution asset base and the cost of the planned programmes, the costs associated with the simultaneous introduction of smarter grids is small, especially compared to the lifetime benefits. While more detailed financial analyses are required, there are numerous business cases demonstrating the financial returns, which can be expected. The Italian system installed by Enel of Italy (Telegestore), which could be regarded as one of the first smarter grid deployments, provides for a very good case study. This smarter grid was completed in 2005 at a project cost of €2,1-billion. This project is providing a return of €500-million per annum. Furthermore, significant business and customer benefits are claimed [3]. Similar initiatives have been successfully implemented in countries such as America, Australia, Europe and the United Kingdom. Therefore, ample international learning experiences are available which can be drawn from.

To leverage the opportunities and to realise the potential to be derived through the deployment of technology to get a smarter grid, it is essential to establish a smart grid vision for South Africa. The next step would then be to align all the efforts, share the learning and to move forward in an integrated manner.

Technology deployment and grid modernisation will lay the foundation for a smarter industry. Getting smarter will take the industry forward and directly contribute to the sustainability of the industry. Furthermore a smarter grid will facilitate enhanced customer participation which in turn will give us smart customers.

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Contact Dr. Willie de Beer,
SANEDI,
Tel 082 338-0854,
wj.debeer@yahoo.com

Smart grid solutions for transformer monitoring and diagnostics

by Dr. Wajdi Ahmad, GE Digital Energy

Transformers form an integral part of the power system value chain. They are used at different voltage levels throughout the power delivery process, starting from step-up operation at the generation power plant and going through various step-down operations to different voltage levels along the way down to distribution voltage levels. Obviously, the degree of transformer criticality depends on the intended purpose of operation. For example, generator step-up (GSU) transformers are extremely critical, as any unplanned outage would mean service interruption to a wide area of customers and possible system-wide instability resulting in unfavourable consequences.

Likewise, some industrial transformers could be small in size but yet very critical for the continuity of the process, and an unplanned outage might entail a big loss of revenue. Therefore, continuous monitoring, full diagnostics and protection of critical transformers are critical and unavoidable tasks for utilities and industries alike in order to maintain availability, avoid damage to life and property, protect the asset and environment, preserve the image of the organisation, and sustain profitability.

Power system faults are unpredictable, and are typically accompanied by increased currents flowing through transformer coils, which would heat up the insulating oil in the transformer tank. Depending on the severity of the fault, the temperature rise in the oil varies, thus giving rise to a mix of dissolved gases of different concentrations. Maintaining good dielectric characteristics of the insulating oil is extremely important.

Dissolved gas analysis (DGA)

DGA has been the method of choice for transformer monitoring and diagnostics (M&D), the goal of which is to detect the levels of dissolved gases and associate them with fault severity. DGA can also help the utility make an informed decision on the level of loadability of transformers after fault clearance by the protection system. It can also offer early detection of moisture and partial discharge, thus helping the utility avoid fast degradation of dielectric strength of the oil that could lead to imminent faults. In this paper we will briefly talk about two methods for DGA.

Gas chromatography method

The traditional method for transformer M&D is based on chemistry of gas chromatography (GC), (see Fig. 1) whereby an oil sample is fed into the analyser, and the constituent gas concentrations are given at the end of the process. Fig. 2 shows the basic components, while Fig. 3 shows the lab setup of the GC system. A typical gas chromatograph consists of an injection port, a column, carrier gas flow control equipment, ovens and heaters for maintaining temperatures of the injection port and the column, an integrator chart recorder and a detector [1].

To separate the compounds in gas-liquid chromatography, a solution sample that contains organic compounds of interest is injected into the sample port where it will be vaporised. The vaporised samples that are injected are then carried by an inert gas, typically helium or nitrogen. This inert gas goes through a glass column packed with silica that is coated with a liquid.

This technique, although very popular and accurate, has been in existence for a long time, and has some drawbacks. First, it is laboratory-based, due to the fact that it requires controlled temperature, pressure regulators, gauges, and flow meters; it also requires an extremely accurate and chemically inert gas that is used to carry the oil sample through the analyser. Inert gases used include helium, argon, and nitrogen. GC is a very sophisticated analytical technique, as gas separation is performed in a very precisely controlled environment where any fluctuation in temperature is disastrous. Detectors used in the analysis process must be maintained at an extremely stable temperature, and the technique is sensitive to vibration, movement, slight changes in flow rates, etc. For these reasons, GC is a bench-top technique and is less suited to applications requiring portability or autonomous operation in a remote location.

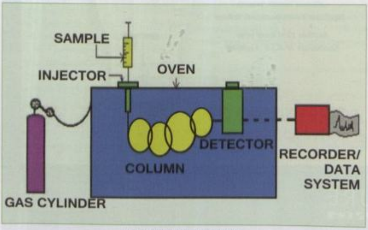

Fig. 1: Gas chromatography system.

Photo acoustic spectroscopy (PAS) method [2]

In contrast, the photo acoustic spectroscopy (PAS) technique has proven very suitable for portable DGA in the field. Fig. 4 shows the basic components of the PAS system. The oil sample to be analysed is irradiated by modulated infrared (IR) light of a pre-selected wavelength. As the gas absorbs energy, it is heated and therefore expands and causes a pressure rise. As the light is chopped, the pressure will alternately increase and decrease, and an acoustic signal is thus generated. The produced acoustic signal is detected by two microphones. The electrical output signals from the two microphones are added in an amplifier, before they are processed.

The merits of PAS for DGA are numerous. This technique has been used to develop portable M&D equipment that can be used to quickly conduct the analysis in the field, without having to wait for the sample to be sent to the lab for analysis. Furthermore, several M&D products have been developed based on the PAS technique to do unattended M&D for transformers. These devices are mounted on transformers, and automatically draw an oil sample that is analysed. The same technique is now being explored to be used for partial discharge analysis, and for cable and switchgear monitoring. Since the technology uses advanced techniques in doing signal processing with communications capabilities, it becomes an easy task to report results continuously to the control room via wired or wireless communications infrastructure.

This analysis can be carried out several times an hour, thus giving the utilities the ability to do continuous monitoring and diagnostics on their transformers. Using PAS, no regular recalibration is needed. This technique is accurate, robust over long timeframes, operates in ambient air, and requires no cylinders of carrier or reference gasses. It is inherently easy to use, with no user interaction required to complete results calculation, and uses minimal serviceable parts. PAS is capable of measuring at very low detection levels (e.g. 0,5 ppm for acetylene) and very high detection levels (>50 000 ppm). PAS is also capable of measuring individual gases in a mixture, and has the ability to move from high gas levels to lower gas levels without cross contamination. It can also give direct measurements of both CO and CO_2, vital gases for understanding cellulose condition of insulating paper, giving increased accuracy and repeatability. Finally, PAS can be used to do measurements on multiple tanks, such as the main tank plus the tap changer tank. Recent advancement in technology has allowed the integration of PAS for DGA with other important transformer monitoring signals such as pressure, Bucholz and temperature to list a few, for an overall monitoring, diagnostic and protection of this very important asset of the power system.

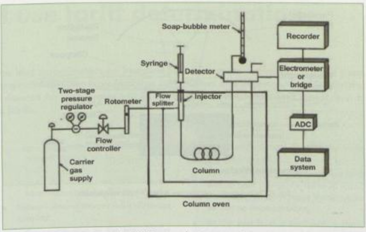

Fig. 2: GC system – basic components.

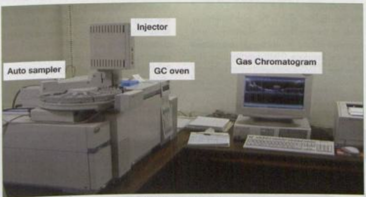

Fig. 3: Lab setup of GC system.

Smart grid integration

Smart grid (SG) vision aims to modernise the power grid and optimise its operation. A holistic vision should address the entire value chain of the power grid in order to reap the real benefits of such modernisation effort. This includes solutions for transmission grid, distribution grid, demand side, work force, and asset protection. The ultimate goal of a smart grid deployment is to make the grid more efficient and more reliable, facilitate renewable integration, increase productivity, empower consumers, and extend the life of critical assets. The underlying platform for all of these solutions is an advanced metering infrastructure (AMI) which comprises smart meters equipped with two-way high speed communications. This is a major transformation of the antiquated grid that is based on one-way power and communications flows. The availability of a high speed communications channel for data transmission paves the way for integration of transformer M&D solutions into the holistic SG framework. Thus, M&D devices deployed at critical transformers in the field can perform frequent collections of DGA data and send it via the communications channel (typically wireless) to the control centre, where advanced software solutions can be used to analyse and interpret this data to assess the health of transformer oil and come up with appropriate decisions and recommendations for an action plan. This closed-loop approach for M&D of critical transformer assets is one of the major attributes of SG solutions, and adds great value to the utility and industrial operations through life extension of such assets. The main feature of the SG asset optimisation solution is that it moves the utility from time-based maintenance approach to condition-based approach, resulting in huge savings on transformer purchases. As such, using advanced M&D devices and solutions within a holistic SG framework and vision will result in better utilisation and life extension of critical transformers.

Hosted asset optimisation solution

Smart grid deployment requires huge investment, which many utilities find difficult to allocate money for. A viable route that could be beneficial to utilities seeking SG deployment is to consider a "hosted" transformer monitoring system (TMS) solution.

In a hosted TMS solution framework, the solution provider assumes all the upfront cost of system and equipment deployment, and the end user will be charged a monthly payment over an agreed – upon period of time, e.g. 20 years.

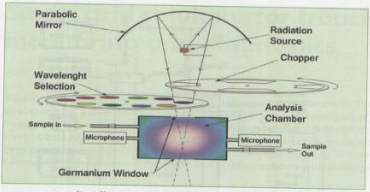

Fig. 4: Photo acoustic spectroscopy system – basic components.

There are two types of transformer monitoring systems available in the marketplace. Centralised systems composed normally by an acquisition unit that is installed close to the transformer and a PC that centralises most of the intelligence, calculations, and communications in addition to the human machine interface (HMI) functionality. The other type of TMS is distributed systems whereby the intelligence is distributed throughout the intelligent monitoring equipment. In the distributed intelligence principle, each of the proposed monitoring devices is an electronic intelligent device (IED) that is capable of executing the online diagnostics pertaining to its functionality, generating the alarms, communicating with other equipment and reporting to operation and analysis software. The TMS IED components are powerful electronic devices with capacity to store data, manage alarms, drive a local HMI through displays and also offer digital communications with open industry protocols. The distributed intelligence of the system and the capacity of the IEDs to support different protocols allow an independence from a central PC. The operations and analysis software is installed on a PC and, through its scheduler, it interrogates each component and stores the data in a centralised data base for expert visualisation and analysis. The distributed TMS continues to monitor other functions of the transformer in the event of component faults.

In a hosted TMS solution framework, the end user gets the benefit of mitigated deployment risk, extended asset life, and investment deferral, while the solution provider collects revenues for an extended period of time.

References:

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Contact Dr. Wajdi Ahmad,
GE Digital Energy, wajdi.ahmad@ge.com

Domestic time of use tariff determination

by Hendrik Barnard, Elexpert

The Government Gazette 31250 requires that smart meters be installed for all customers consuming more than 1000 kWh/month by 1 January 2012. Many municipalities have installed such meters and implemented TOU tariffs. Many of these tariffs leave much to be desired for. This paper will illustrate the requirements and features of a quality domestic/small commercial TOU tariff.

The tariffs that are being applied by some municipalities do not qualify in terms of the stipulations in the South African electricity pricing policy (EPP). Various requests have also been made for a paper to provide guidance on the determination of TOU tariffs for domestic customers. This paper provides insight into some of the dynamics of applying a TOU tariff for domestic customers and give guidance on how such tariffs should be set.

Objectives

It is important to understand the objectives of implementing smart meters with load management features on TOU tariffs:

- To ensure electricity tariffs which reflect the cost of supply as accurately as possible in respect of the all various type of costs.
- To encourage and support load shifting by customers in an economically efficient way.

This paper will show that it is important that load shifting must not be ensured at all cost but be in response to the economically efficient price signals. A lot of money will be spent on installing meters and management systems. It is therefore essential to ensure that price signals will provide critical drivers to ensure optimal load shifting.

EPP stipulations

Before any tariffs can be set it is essential that the stipulations in the EPP be studied and applied. The ones critical for determining domestic TOU tariffs state that efficient electricity prices would lead to:

- Optimum allocation of scarce resources including financial, human and natural resources.
- Optimum usage of electricity.
- Optimum usage of the different energy forms (e.g. electricity, gas, oil and coal).
- A financially viable industry.

Policy position: 27

NERSA must see within five years that cost reflective tariffs shall reflect all the following cost components as far as possible:

- *Energy costs in c/kWh:* The energy cost from the bulk supplier or other sources differentiated by:
  - the bulk supplier TOU periods
  - or, with non-TOU metering, the relevant portion of the various TOU costs.
  - plus the losses on the relevant transmission and distribution networks.
- *Network demand charges in R/kVA/period covering:*
  - the contribution to the transmission network costs by the relevant loads.
  - plus the variable (shared component) of the DUOS costs.
- *Network capacity charges in R/kVA/month or R/Amp/month based on annual capacity:* the fixed or dedicated component of the DUOS costs
- *Customer service charges in R/cust/month:* covering the costs of providing the services to serve the customer including, billing, revenue collection, marketing and customer claims
- *Point of supply costs R/POS/month:* covering the costs associated providing each connection customer from the point of common coupling and metering
- *Cost of poor power factor:* Charges may be levied to reflect the avoided costs for the distributor if it had to restore the power factor to the optimum level

Policy position: 29

Tariff structure and levels shall be aligned with the results from the COS studies in which the resultant income will equal the revenue requirement.

Policy position: 30

Cost reflective tariffs are considered the most effective pricing signal to be provided to customers. Any additional pricing signals over and above the costs must be motivated specifically and be approved by NERSA.

Policy position: 32

TOU tariff energy charges must be differentiated by:

- All the components as reflected by the WEPS
- In addition a super peak rate to reflect the short terms costs could be applied during emergencies in which case customers need to be informed in advance

Policy position: 36

Domestic tariffs to become more cost-reflective, offering a suite of supply options with progressive capacity-differentiated tariffs and connection fees:

- At the one end a single energy rate tariff with no basic charge, limited to 20 A and nominal connection charge (details under section on cross-subsidies).
- At the next level a tariff with a basic charge, customer service charge, capacity charge and energy charge with cost-reflective connection charges.
- At the final level TOU tariffs must be instituted on the same basis as above, but with TOU energy rates.

Tariff structure

In view of the EPP stipulations and the practicalities in the Southern African EDI the following tariff structure is proposed:

- *Basic charge (Rand/customer/month):* This to be set as close as possible to the fixed/customer services costs associated with a domestic TOU customer. This should be differentiated for 1 and 3 phase customers and bulk domestic.
- *Capacity charge (Rand/A/month):* This is to be based on the installed capacity per customer (set per 10 A) and be set as close as possible to the network costs which must include capital provision and maintenance.
- *Energy charges (c/kWh):* This to be as close as possible to the WEPS (Eskom Megaflex)
  - Peak, standard and off-peak
  - High demand/Low demand seasons
  - All periods to be the same as the Eskom TOU periods
  - Reactive energy charge

There are some controversies in this respect which will be discussed later in the paper:

Tariff level

The setting of the tariff levels presents a bigger challenge than the tariff structure. The following should be considered in this respect:

- Each utility currently has a certain level of cross subsidation between various tariff categories and between different customers within a particular tariff category.
- The introduction of domestic TOU tariff should not just change the cross-

subsidisation dispensation between different tariff categories.

- This means that the revenue received from the target domestic TOU customers should remain the same when converted to the TOU tariff from the existing tariff.
- Cross subsidisation between tariffs can change but then it must be a clear, deliberate phased approach.
- This does however mean that within the domestic TOU customers the intra-tariff cross subsidisation will be removed: In respect of load factor and relative usage in different periods.

The following process is thus proposed in respect of setting the tariff level:

- Determine the revenue from these customers on the current tariffs.
- Determine the various per unit costs: basic costs, network costs and energy costs for domestic TOU customers, this to include the municipal surplus.
- Determine the various usage quantities for these customers: Number of 1 phase and 3 phase, bulk, capacities of these, and energy per usage period.
- Simulate the revenue using per unit costs and the usage quantities.
- Adjust the per unit costs to achieve revenue neutrality with the existing revenue as follows:
    - Increase the TOU energy rates by the same c/kWh surcharge for all periods.
    - Retain all other charges as per cost calculations.
- This will imply that the cross subsidisation to other customers (big reason for any increases) will be covered in the energy charges.

Conversion strategy

One of the key aspects which influence the setting of the tariff level relates to how customers will be converted to the TOU tariff. The following options exist:

- Give customers the choice to convert. This is not in line with the EPP and other government stipulations and also causes only those customers who will save to convert.
- Give no choice. This is the preferred route. Obviously not all domestic customers using more than 1000 kWh/m have smart meters installed and therefore not all can be converted to TOU at once.
- It is suggested that all customers for whom smart meters have been installed be converted as from the start of the new financial year. If customers are converted during the year, the municipality will almost always lose revenue.

What is important to consider is that once customers are converted, their load factor and TOU consumption ratios will change. The after conversion consumption ratios cannot be used for future revenue neutrality calculations.

Cost analysis

The EPP is clear that the basis for all tariffs should be cost. That requires that a COS study be undertaken but this is problematic in that most municipalities have not done these yet. A simplified COS study should however be done focussing on the domestic TOU customers. This process is explained below in a very simplified way:

Basic costs

Analyse the detailed budget and extract all fixed/customer services type costs such as:

- Metering reading
- Vending
- Revenue collection
- Billing
- Customer services

Now obtain details of all customers per category 1 or 3 phase. Allocate a cost weight factor to each and calculate the equivalent domestic 1 phase and 3 phase customer per unit cost.

Determine the smart meter capital cost, expected life and cost of capital and calculate the cost per month per smart meter for 1 and 3 phase.

Add the customer services costs to the meter capital provision to obtain the proposed fixed charge.

Capacity costs

Analyse the detailed budget and extract all network related costs such as:

- Network staff costs
- Network maintenance costs
- Network operations costs
- Vehicles and contracts relating to networks
- Fault centre and control room costs
- Interest and depreciation on networks

Determine the total installed capacity as the sum of individual customer capacities.

Now divide the total network costs by the installed capacity and 12 to obtain Rand/kVA/month and then convert to R/A/month

The issue of Eskom basic charge, maximum demand and access charges can be interpreted as follows:

- It can be considered a capacity/demand cost and thus be treated as a R/kVA/m charge. If so calculate the basic charge, access charge, maximum demand charges for the previous year escalated to the new period and divide by the total installed capacity to obtain a R/Amp/month and add to the capacity charges.
- It can be treated as an energy cost and thus be converted to an energy charge. If so: Calculate the basic charge, access charge, maximum demand charges for the previous year escalated to the new period and divide by the total energy purchased for that period and add to the energy charges.

Adding it to the capacity charge is the preferred option because:

- It is a more fixed/kVA cost. In other words if customers increase their maximum demand/capacity, most of these costs would increase.
- If the energy consumption increases but the maximum demand remains the same, these costs would remain the same.

Energy costs

Obtain the Eskom tariff charges applicable (Megaflex), determine the energy charges applicable at your location (include Eskom losses) and then add to the all six energy charges per period the following:

- Electrification and rural subsidy
- Environmental levy

Now estimate/calculate the local network energy loss factors for each of the six TOU periods. This could be done as follows:

- Determine/estimate the total technical losses for the utility
- Determine/estimate the total losses at LV level

Customer cost analysis		Number customers	Ref weight ratio	Total equiv. customers	Per customer R/kVA/m
Small	1 phase	34 246	1	34 246	47,85
	3 phase	1431	1,2	1717,2	57,41
Medium	1 phase	1091	2	2182	95,96
	3 phase	1780	2,2	3916	105,26
Agric	3 phase	1041	3	3123	143,53
Large	LV 3 phase	348	10	3480	478,45
	MV 3 phase	121	30	3630	1435,36
		Total equivalent 1 ph		52 294,2	
Total fixed/customer services costs			50%	R30 024 500	
Total cost per 1 phase customer				R47,85	

Table 1: Basic cost per customer.

Eskom network charges		Total access	Total access and demand	Convert to installed	
Transmission access	R4,41	R14,26	R30,66	Maximum demand	157 000
Distribution access	R9,85			Installed capacity	944 000
Distribution demand	R16,40			R/kVA/month installed	R5,86
	Escalated to 2012/13	R/kVA/month	R35,26	R/A/month	R1,30

Table 2: Eskom fixed charges.

Budget analysis		
Electricity purchases from	**Budget (2012/13)**	
Eskom	R390 112 000	
Salaries and maintenance	**Budget (2012/13)**	
Salaries, wages and allowances (own staff)	R14 004 000	
Repairs and maintenance (excluding salaries and allowances)	R25 778 000	
Total	R39 782 000	
Capital charges	**Budget (2012/13)**	
Interest – external loans	R13 765 000	
Bad debt reserves	R7 532 000	
Total	R21 297 000	
Other expenses	**Budget (2012/13)**	
Charges allocated from other municipal departments	R0	
Charges allocated to other municipal departments	R23 404 000	
General expenses	R60 049 000	
Total	R83 453 000	
Purchases **Total exc purchases** **Total cost**	**R390 112 000** **R144 543 200** **R534 644 000**	
Total network cost (inc 75% of gen)	R137 000 000	
Depreciation	R760 000	
MD	157	MVA
R/kVA/year	R72 717,72	R/kVA/y
c/kWh	18,026	c/kWh
Surplus % of cost	24,0%	
Net network cost	R90 142,30	
Network cost	R47,85	R/kVA/month
Plus Eskom MD charges	R28,48	R/kVA/month
Total	R76,33	R/kVA/month
Capacity cost	R2,82	R/Amp/month

Table 3: Utility own network costs.

- Differentiate the losses by time period based on simple engineering principles. In other words losses are proportional to the square of the average current in each period.

Now multiply the six energy rates by the respective energy loss factors and finally adjust the various energy rates by the same fixed c/kWh surcharge to obtain revenue neutrality for the target customers.

Example

The example below gives some insight into how these calculations should be done.

Basic costs

Table 1 below shows an analysis of customer numbers and calculation of equivalent costs per customer.

Eskom energy charges	c/kWh	c/kWh	c/kWh
2011/12	**Peak**	**Standard**	**Off Peak**
High demand season (Jun – Aug)	186,05	48,38	25,87
Low demand season (Sept – May)	51,95	31,83	22,28
Levies	4,11	2,00	
Escalation to 2012/13	Increase	15%	
Energy rates including levies	**c/kWh**	**c/kWh**	**c/kWh**
High demand season (Jun – Aug)	213,96	55,64	29,75
Low demand season (Sept – May)	59,74	36,60	25,62
Loss factors	**Technical losses at LV**		**10%**
High demod season (Jun – Aug)	15,0%	10,0%	7,0%
Low demand season (Sept – May)	15,0%	10,0%	7,0%
Net energy costs at LV			
High demand season (Jun – Aug)	246,05	61,20	31,83
Low demand season (Sept – May)	68,70	40,26	27,42

Table 4: Eskom energy charges.

Demand/capacity costs

The calculations of the capacity costs starts with the analysis of the Eskom fixed charges. This is shown in Table 2.

The next step is to calculate the utility own network costs (see Table 3).

This is then converted to a charge based on installed capacity by dividing that by a ratio of maximum demand divided by customer installed capacity.

Energy cost

The objective is to have one single energy rate for all time periods. This starts off with the analysis of Eskom charges to the utility. This is shown in Table 4.

Revenue neutrality

The final step in tariff design is to establish revenue neutrality. The proposed method is as follows:

Determine the relevant details of the target customers of those with TOU meters which are to be converted and for which data has been obtained. The Table 5 is an example of data required for each custiomer.

Once this data has been determined the revenue from the existing domestic tariff after application of the average price increase is compared with the revenue from rates calculated above. The TOU energy rates are then all adjusted with a fixed c/kWh to yield the same revenue from the TOU tariff.

In the example the break-even is achieved at a mark-up of 18,79 c/kWh on the Eskom effective TOU energy rates. The resultant charges are as shown in Table 6.

The impact on customers is very important to address when the conversion process is compulsory. Fig. 1 indicates the impact on customers at various load factors.

In my experience less than 5% customers will be subject to an impact of more than 15% due to structure change.

Issues

There are a few controversial issues that will now be discussed:

Two period vs. three TOU day periods.

A few utilities have been advocating a 2 day periods (peak and standard combined into a new peak). The only motivation provided is that no more significant load shifting has been detected going from 2 to 3 periods. It is believed this is not correct because of the following:

- The EPP clearly stipulates that the tariff structure needs to be as close as possible to the WEPS. Therefore three periods should be used.
- When a two rate period is applied the very high price signal associated with the Eskom peak periods is negated because the rate for the new peak (peak and standard) the average of the two will be significantly less. This is in contradiction with the EPP in terms of ensuring efficient allocation of resources.
- The biggest issue relates to the ability for customers to move load effectively and avoid the Eskom peak times. This is illustrated by some examples:
  - Customers with solar water heaters usually require that some electrical heating in the late afternoon if the water did not heat up adequately. With the two rate period the optimal time would be from 18h00 (exactly on Eskom peak) when the sun is close to setting. With the three rate the boost can be done from 17h00 to 18h00 which is in the Eskom standard period.
  - Customer with solar panels for their swimming pools can run from 10h00 to 18h00 totally avoiding the Eskom peak period. With the two rate there

Customer A		Peak	Standard	Off-peak	MD - kVA All	ME - kW All	MD P&St	MD highest	MD highest	kWh Tot
	Days	**kWh**	**kWh**	**kWh**	**kVA**	**kW**	**kVA**	**kVA**	**kW**	**kWh**
1 Jan 2011	31	94	244	379	2,5	2,5	2,4	15,0	14,9	717,1
1 Feb 2011	28	174	478	577	15,0	14,9	15,0	15,0	14,9	1228,0
1 Mar 2011	31	79	202	543	2,8	2,8	2,8	15,0	14,9	524,1
1 Apr 2011	30	170	417	377	12,0	12,0	12,0	15,0	14,9	963,6
1 May 2011	31	98	257	384	2,8	2,8	2,8	15,0	14,9	738,8
1 Jun 2011	30	55	254	157	1,7	1,7	1,7	15,0	14,9	466,3
1 Jul 2011	31	56	218	195	1,4	1,4	1,4	15,0	14,9	469,2
1 Aug 2011	31	65	191	211	1,5	1,4	1,5	15,0	14,9	466,7
1 Sept 2011	30	68	180	225	2,3	2,3	2,3	15,0	14,9	472,6
1 Oct 2011	31	175	427	416	12,0	12,0	12,0	15,0	14,9	1018,0
1 Nov 2011	30	93	246	346	2,8	2,8	2,8	15,0	14,9	685,1
1 Dec 2011	31	97	257	359	3,9	3,9	2,6	15,0	14,9	712,6
1 Jan 2012	30	1222	3370	3870	61	60	59	180	179	8462

Table 5: Data required for each customer.

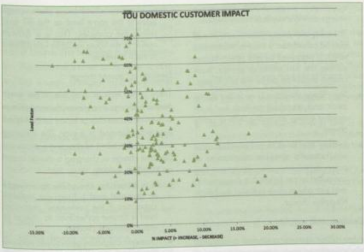

Fig. 1: TOU domestic customer impact.

Domestic TOU tariffs			01-Jul-12		
			Basic charge		Energy charge
Tariff name	Code		R/month		c/kWh
Existing 2 part	1 ph		200,00		89,00
	3 ph		900,00		89,00
Domestic TOU	1 ph		Basic	Capacity	
			R/month	R/A/month	
			57,41	2,82	89,00
			Peak	Standard	Off-peak
			c/kWh	c/kWh	c/kWh
		Energy: high demand	264,84	79,99	50,63
		Energy: low demand	87,50	59,06	46,21
Domestic TOU	3 ph		Basic	Capacity	
			R/month	R/A/month	
			57,41	2,54	50,63
			Peak	Standard	Off-peak
			c/kWh	c/kWh	c/kWh
		Energy: high demand	264,84	79,99	50,63
		Energy: low demand	87,50	59,06	46,21
		Markup		18,79	c/kWh

Table 6: Eskom energy charges.

is no incentive not to start at 08h00 in the peak time.

- The same applies to washing machines and dishwashers especially where domestic workers are only at home during the day. For them there is no advantage to only start at 10h00 avoiding the Eskom peak.
- There are various other applications with a similar need to run during the day but not all day. Even if fridges are equipped with timers they can be set to avoid the Eskom morning and evening peaks with a three rate whereas it is not possible to switch them off for the whole day from 07h00 to 10h00.

- Other issues relate to the setting of the tariffs. When customers shift load, the revenue impact to the utility will not match the savings in energy cost to Eskom (WEPS for Eskom Distribution). This means that a detailed and complex revenue neutrality calculation will have to be done every year.

Treatment of public holidays

The issue of the treatment of public holidays also brings a decision to be made. The following can be said in this respect:

- The different treatment of public holidays as per the Eskom Megaflex is the more cost reflective option.
- It is unlikely that domestic customers would take specific effort to make maximum use of the cheaper power during some public holidays.
- If public holidays are not treated differently the P/S/O-P quantities should be calculated treating public holidays as normal days to ensure fairness.
- If a smart meter system without remote ability to load the public holidays as different days is used, it is not advised because of the need to visit the meter and reprogramme it annually. (This is the case with some large customers on TOU).

Reactive energy charges

Megaflex contains a reactive energy charge and many utilities have to implement power factor correction due to customers' reactive loads. The following in this respect:

- Historically domestic loads have been very resistive. The loads are however becoming more reactive because of the following:
  - Less resistive loads with solar water heaters being installed, less electricity for cooling and space heating.
  - Heatpumps used for water heating, more CFLs and LED lights and various electronics generally with poor power factors.
- Customers best way of managing the power factors is:
  - By the equipment they purchase. The problem is that power factor labelling is not generally done in South Africa.
  - By using motor driven appliances such as heat pumps mostly during the off-peak times when power factor is usually not a problem.
- In recent studies done for domestic customers using more than 1000 kWh/m, it was found that on average the power factor is worse than the excepted 0,85%. Reactive energy exceeding 30% of the active energy during the peak and standard period only is as much as 7% of the active energy.

Based on this information the case can be made to charge a reactive energy charge. The following in respect of such charge:

- It should cover the Eskom reactive energy charge which is applicable in peak and standard periods during the high demand period only and charged for such quantities in excess of 30% of the active energy during every half hourly period.
- The utility own power factor needs should also be considered. If there is overloading which is worsened by bad power factors during the low demand period, such charge should be set for the whole year.
- The charge should only be levied during peak and standard periods for such reactive energy exceeding 30% of active power.
- Setting the level is a complex issue which needs complex assessment of power factor correction equipment cost converted to per kvarh. It is suggested to start with a level close to that of the Eskom Megaflex charge.

Domestic bulk supplies

A few million domestic customers are supplied via a reseller or body corporate within either a complex or flat.

Historically these customers were given a bulk supply tariff very close to the domestic tariff. With the NERSA introduction of heavily subsidised inclining block rate tariffs (IBT) for domestic customers, a big problem has been created:

- If a bulk domestic TOU tariff is developed which breaks even with the customers using more that 1000 kWh/m as in the rest of the municipality, a big problem will be created.
- Municipal and national legislation requires that all customers within a municipal boundary be treated fairly. In this respect the EPP also stipulates that customers of resellers should not be charged unfavourably relative to customers supplied directly by the municipality.
- With the IBT tariff available to customers using less than 1000 kWh/m, customers with lower consumption received massive cross-subsidies.
- Studies has clearly shown that if a domestic TOU tariff calculated for revenue neutrality for domestic customers using more than 1000 kWh/m is applied to reseller, the revenue from the IBT would be significantly less than the price at the domestic TOU tariff.

This is a complex issue which seems to be flawed with many challenges. The following options hold a possible solution:

- Do not apply a domestic TOU tariff to these resellers but charge an IBT where the blocks sizes are multiplied by the number of units supplied in that complex. This is the most simple but fair approach but the TOU message is not getting to customers of the reseller.
- Offer a bulk domestic TOU tariff where the c/kWh markup is set at a level which would bring the average price to the same level as the IBT tariff within the complex. This is a difficult option as the figure would be very different to each complex.

Demand vs. access charge

There is the feature available in the smart meters to charge a maximum demand charge or even an access charge based on the highest maximum demand in a year. The following can be said in terms of charging a maximum demand charge vs charging a charge based on installed capacity.

- It is better for the utility to manage its demand and subsequent network capacities if the customers' maximum load is limited rather than to charge by way of demand charges.
- Domestic customers generally do not have the sophistication or time to manage their loads on an hourly basis.
- Experiences in many municipalities is that customers are aware of their capacity limits and do take measures to remain within the contracted capacity.

Based on the above it is proposed to charge a R/A/month charge rather than a maximum demand or access charge based on measured demand per month. It is also proposed that steps of 10 A be provided for in the selection for customers.

Load control by utility

The smart meters must make provision for the management of various loads of the customer remotely by the utility. The controversial issues in this respect are as follows:

- The capacity charge and the TOU energy rates should provide a very strong signal for customers to avoid the Eskom peak times and the local peaks which would mostly coincide with customers own peaks.
- When utilities now manage some of these loads remotely the following questions arise:
  - Will it not compromise the customers' TOU energy cost? For example if the utility interrupts the solar water geyser load from 16h00 to 18h00, the customer will need to heat the water during the peak time to be able not to have cold water.
  - If an air-conditioning unit is interrupted from 06h00 to 07h00, the customer may usually have pre-heated the house before the peak which he would now need to do during peak time.
  - If any such reductions are part of Eskom's demand market participation (DMP) plan, should the customer not be credited with any such payment to the municipality?

The key message here is that great care would need to be taken in doing the system setup closely with customers.

Time periods/seasons different from Eskom

Some utilities have opted to apply TOU day periods and seasonal months different from that of Eskom. The following in this respect:

- The objective is to set tariffs equal to cost.
- The energy charges must thus cover energy cost.
- The capacity charges must cover network costs.

Applying periods different to that of Eskom WEPS is not supported.

Method of mark-up for revenue neutrality

Various methods can be followed in marking up the basic costs as calculated to obtain revenue neutrality. The following options can be used:

- On all charges or only some.
- The same or different surcharges on different charges.
- The same % or same c/kWh on energy charges.

It is proposed that the mark-up be done as follows:

- On energy costs only.
- As a fixed c/kWh on all energy charges.

This is motivated as follows:

- If the surcharge is applied to energy only, the customer can at least save a little bit more when reducing consumption.
- In this time of energy shortages in the country, the need to save energy is important.
- If the surcharge is the same c/kWh on all energy charges, the utility will remain net revenue neutral when customers shift load.
- The Eskom TOU price signal is not distorted. If it is distorted by say applying a much higher surcharge on peak energy, "the efficient allocation of resources" objective will not be obtained.

One of the most common mistakes made by utilities in the design of their TOU tariffs is to mark-up the Eskom energy rates by the same or similar percentages. When customers shift load from an expensive to a cheap period, the utility will lose more revenue than what it saves in Eskom purchase costs. This has led many utilities, including Eskom, at one stage to discourage any load shifting.

Cross-subsidy, renewable energy levy

Some utilities are showing many different charges for example: renewable energy levy, cross-subsidy levy, etc. The following should be noted in this respect:

- Considering the increased complexities of domestic TOU customers do we really want this further complexity?
- If the customers are on pre-payment, they will not even see these separate charges.
- If the various cross-subsidies / levies are worked into the relevant rates, the pricing signal will not be distorted.
- When the rates applied by Eskom are applied at the LV level, it needs to be adjusted because of losses. In other words the charge must be higher than the Eskom charge because of losses to be cost reflective. If a higher charge than that of Eskom is charged, negative customer reaction could be expected.
- Because the renewals energy levy is a charge on generators and thus a cost to customers, even Eskom is considering not showing it separately in future.
- It is expected that the domestic TOU customers will make a contribution to the cross-subsidies in the utility.

To be able to show this levy would require that a detailed cost of supply study be undertaken regularly.

In view of the above it is proposed to include these charges/levies to the appropriate tariff charges.

Pre-payment vs. conventional payment

One of the drivers in South Africa has been to convert domestic customers to pre-payment. Applying pre-payment to domestic TOU tariffs with smart meters presents new challenges in this respect. One of the big challenges associated with pre-payment meters currently being used in South Africa is that the customer pays in Rand but receives a token for kWh. This causes a problem when customers purchase very large quantities at the low price just before any price increase thereby causing the municipality to lose money. This problem would be very prominent with the TOU tariffs associated with much higher rates during the high demand season.

If domestic TOU tariffs with smart meters are applied it is therefore proposed that the customer purchase Rand amounts and that the Rand amounts are transferred to the meter. The meter will contain all the tariff charges and will thus deduct the associated amount from the available credit on the meter. This is further complicated because of the following:

- When the end of the month comes and the basic charges plus capacity charge is deducted that the customer could go into a negative credit available.
- If the customer does not purchase any electricity, the amount due will increase every month.
- Consideration should thus be given to deducting the fixed charge by way of a debit order and only vending the energy.
- Various payment options are being considered to ensure that these, typically more sophisticated customers, can determine the available credit remotely and make payments remotely.

Load shifting support

Load shifting by customers does not take place by itself. Even if the tariff contains a capacity charge and TOU energy charges, and the system has load management contacts, customers need support in this respect:

- A consumption/requirement audit should be undertaken per household.
- The customer need to be recommended what optimal load management regime would be optimal.
- A joint decision be made and the system then be configured to operate in terms of this regime.
- Customers need to be informed about the effectiveness of the system on total electricity costs and their bills.

Capacity costs / fixed costs in energy charges

Various utilities have implemented TOU tariffs with energy charges only. The following problems are experienced when fixed and/ or capacity costs are included in the energy charges:

- This distorts the price signals. Customers will now make inefficient decisions. This could for example signal to customers that it is better to use an electrical heater because the few hours of winter peaks are still much less than the increased capacity costs for the whole year.
- There is no signal for customers to improve their load factor and thus installed capacity which have an impact on utility supply costs.
- This will cause customers to increase network capacity/system peak for a few incidents during the year. It is well known that there are a few days in year, usually associated with very cold or very hot weather which causes big system constraints.
- Customers with irregular consumption will not pay their fair cost of supply. This means that customers, who have a second property and only use the supply for a few months in the year, will be subsidised by those customers with one property only and more consistent usage throughout the year.
- When all costs are loaded onto the energy charges, the utility is more exposed to consumption changes by customers. When customers reduce consumption but not required capacity, the utility costs remain the same but experience big revenue losses are experienced.

Implementation

The roll out if any new system is associated with teething problems. The following is therefore proposed in this respect:

- That the smart meters be installed and be run as a simple non-TOU tariff on conventional payment mode.
- Because of the big difference in rates between the seasons it is proposed that customers only be converted to the TOU tariff at the start of a new financial year. New customers can be charged at TOU from the beginning.
- When a customer that is currently on pre-payment, converts to the new smart meter in conventional mode, a deposit needs to be levied for that customer.

Conclusions

The development of a TOU tariff for domestic customers is a complex subject. This paper highlights some of the key considerations. Municipalities are advised not to just jump in and do their own thing. Thorough analysis and various practical and ideological issues need careful analysis and considering. It is hoped that this paper has provided useful guidance that can be used by all electricity utilities.

Contact Hendrik Barnard,
Elexpert, Tel 083 654-8402,
hbbarnar@mweb.co.za

Building a real smart solution

by Tom Phillips, Conlog

Many countries are still coming to terms with the sudden and debilitating financial crisis of 2008. Some governments have been able to stave off the world recession by pouring reserve funds into public works programmes, but these coffers are now empty.

It is within this context that we have seen the rapid adoption and deployment of revenue protection and management systems globally. In particular, we have witnessed the exponential increase in standard transfer specification (STS) IEC62055-41 projects in many emerging markets.

The increased popularity of STS can be seen by the number of companies (many international) who are becoming active members of the STS Association, the body responsible for the governance of the specification.

In addition to the financial crisis, there is growing concern over our environmental health, including the sustainability worries over our global energy resources. There is a palpable change in the consumption habits of our world's population. This, however, has been predominantly in the affluent (dare I say) first world economies. In many of our emerging markets the general population are lower down on Maslow's hierarchy of needs. The supply of basic resources and services for these customers is less than guaranteed.

These two global crises have caused a substantial shift in project funding, leading to a massive switch to service supply projects that are aimed at efficiency and appropriate use of resources.

The momentum to "smart solutions", whether meter or grid, has raised as many questions as it has answered.

It is within this seemingly confusing context that we have determined the pressing need for a system that is both financially sustainable and functionally appropriate.

The customer

Putting the proposed system into context, it is necessary to expound on our target market. The majority of our customers will consume less than 7 kWh/day. Comparing this with a European daily average of 18 kWh/day or the USA average of 39 kWh/day one can see that the introduction of expensive smart metering technology into this business case is financially not viable.

There are some rural communities that use, on average, less than 2,4 kWh/day (see Fig. 1). It is patently clear that any solution for these customers needs to be substantially different to that deployed in Europe and the USA.

The real smart solution

The proposed solution is a radical departure from those that have gained such notoriety to date. Virtually every magazine and conference targeting electrification programmes or the electricity utility market has at least one article on smart grid/smart metering applications. The global market is saturated with the hype associated with smart metering and the benefits and concerns over this technology.

One of our most prominent system drivers when defining the architecture of a smart metering system was the adoption of a sustainable prepayment revenue management model that will see the capital investment redeemed within a few years.

Advocates of the first world smart metering and smart grid systems would argue that including the element of prepayment in these systems is an unnecessary overhead and adds complexity. However, as will be detailed, the inclusion of prepayment into the system builds in a redundancy and a flexibility that are both appropriate and convenient for the utility and customers alike.

The proposed smart solution does not compete directly with the "first world" (high consumption consumers) smart grid/smart metering systems, but rather is a "bottom-up" approach that is appropriate for both low consumption and high consumption end-users using field proven prepayment metering building blocks. The solution is both modular and extensible.

In the conventional smart grid/smart metering systems the cost per point of supply is typically several thousand rand. The business case for such a system to be rolled out to low end electricity consumers just does not give the utility any return on investment (ROI). In South Africa it was to be legislated that end-users in excess of 1000 kWh per month should have a smart meter installed on their premises.

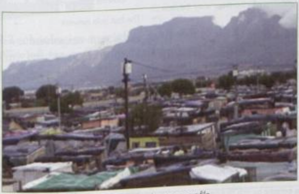

Fig. 1: Our typical customer profile.

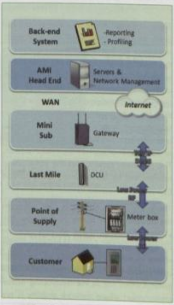

Fig. 2: Basic system architecture.

Our question is, why limit the technology to high-end customers? Why not deploy a solution that benefits all users (while being financially viable)?

Fig. 2 shows a system view of the alternative smart metering/AMI capable system that meets the basic requirements of the utility while still being affordable and expandable to the entire market. It is a compromise between functionality and affordability while being inherently expandable.

Keeping everyone talking

Fundamental to the solution is the element of interconnectivity between different systems. It is imperative that standard protocols and norms be used between communications nodes. One such protocol is the DLMS/COSEM (device language message language) which has been adopted internationally in many smart metering applications.

System elements

Using the diagram in Fig. 2, each system element will be discussed in detail. The system can be deployed in a phased manner to accomplish a functional smart metering/AMI system. The proposed system uses the humble prepayment meter and in some circumstances even the previously installed meters can be enhanced to offer remote metering functionality.

Many smart metering systems use GSM modems in each and every meter. Our practical experience has shown this to be logistical nightmare with increased operational costs attributed to the management of the assets and the operational charges associated with the network connectivity and maintenance.

There has been some controversy and bad press regarding the application of radio frequency for last mile communications to the meter. It has to be noted that the meters in question used either GSM communications or Zigbee communications technology. Our own research and development have shown that these technologies, while inherently robust, open (from a standards perspective), and offering adequate range, have done so at the expense of higher transmission powers. The proposed system uses the same power transmitted by an ordinary gate/garage opener or car remote control device.

There are some detractors that advocate the adoption of a purely on-line type AMI system. Many of these players operate in a first world, developed environment where communications network coverage and speed are taken for granted. These systems often fail in the developing nation environment where network stability is not guaranteed. With the merging of AMI and

Fig. 3: Customer user interface.
Fig. 4: Measurement and control unit.

prepayment systems there is an element of redundancy afforded by the combination system.

When the communications network is down for any length of time, customers can still top up their credit using standard prepayment electricity tokens.

The financial model of prepayment facilitates funding of often neglected disciplines of maintenance and seed funding for network expansion. It uses the common banking principles of gearing that ensure continual system enhancement and upgrading.

The premises

Fundamental to the system architecture is the concept of separating the user's interface and the metering unit (commonly known as 'split metering').

This configuration has become a norm, at least in the international markets, showing increased revenue protection and a deterrent against tampering. (Customers have a propensity to become very possessive about their integrated meter and customer interface unit when they have attempted to bypass the unit). Under these circumstances, the customer is seldom found at home when the utility comes to visit.

It has been our experience that banks are very keen to assist with financing these projects because they can identify completely with the financial model. Where things get tense is where funds have to be switched from country to country, where both financial and political stability of countries may be less than guaranteed.

The point of supply

The smart metering unit is mounted at the point of supply and is often pole mounted, or mounted in a street kiosk.

In many of the targeted markets there are additional challenges to be faced. Reticulation networks are often overloaded or have not kept pace with the expansion of the network, leading to excessive voltage fluctuations and network instability. In many first world environments the quality of supply is taken for granted, whereas in our environment the voltage fluctuations can be as extreme as ±50% from the nominal voltage. To exasperate an already harsh environment the cabling is regularly under-rated for the continual load, most commonly because the cables are aluminium and the rule of thumb 1,6 times copper rule has not been applied. (A 10 mm² copper cable can operate continuously at 60 A. An aluminium cable with similar capacity should be 16 mm² [1,6 x 10 mm²]).

International certification requirements do not specify these voltage extremes and therefore many smart metering products have difficulty operating in these environments.

Associated with the increased technical diversity required are new installation techniques and requirements. A basic understanding of the associated technologies deployed is often advantageous to ensure optimal and reliable system operation. Stories abound of the most horrendous installations that advertise the installation contractor's ignorance of the technical requirements:

While this may seem rather alarmist, it is wisdom that has been learned in the school of hard knocks.

Requirements borne out of these extreme environments include;

- The sensing of terminal temperature (to avoid irreparably damaging the product due to under rated cabling, poor termination and incorrect wiring).
- Extreme voltage capability. The normal certification standards require products to operate over a dynamic range of -20% and +15% of nominal voltage. Real world requirements in many of the developing countries would indicate ±40% to be a basic minimum requirement.
- Delaying reconnecting the customer's load after a power outage (using a random delayed reconnection algorithm) to reduce the network inrush currents, particularly at the feeder transformers.
- Monitoring both the end-user's power and current usage (STS only stipulates disconnection on an over power condition). As previously highlighted, with poor reticulation voltage control, over current conditions can persist with extreme under voltage.

The last mile network

This is the bridge between a standalone metering system and the ability to be connected remotely. It is also a critically important element where all the accumulated data is concentrated and communicated upstream to the head end system using whatever communications medium available.

The data concentrator may utilise GSM technology, but this is not mandatory, there are many options associated with the choice of the communications technology in the back haul system. Piggybacking on an existing SCADA system is just one of many alternate

Fig. 5: Typical pole mounted installation.

communications backbones that are used to keep the operational costs to a minimum.

Suffice to say that it is also imperative to ensure that there are system redundancies to ensure that data integrity and availability are not compromised.

Network communications can be either scheduled or event driven, the majority being scheduled with regular meter information reading. Event driven communications will occur only when predefined trigger points are registered, such as tamper detection or low credit enunciation.

With the system's two-way connectivity comes the ability to add functionality that assists the utility in the management of their reticulation system. Such functionality includes:

- Remote meter reading (of registers and status).
- Remote customer management with remote connection and disconnection.
- Energy balancing.
- Customer consumption profiling, assisting with network capacity planning and management.
- Demand side load management, whether scheduled or unscheduled (e. g. when a bulk feeder goes down).

The simplicity of the solution means the infrastructure can be rolled out a little at a time, wireless prepayment meters first, using a handheld remote data capture/interrogation unit for remote data collection, thereafter expanding the system with the installation of data concentrator units (DCUs) with a head end system that manages both the network and the data.

The system can be further expanded with the use of smart switches. These are load switches in the customer's residence. The smart switches control household geysers, pool pumps, under floor heating elements, air conditioners etc.

The head end

The head end comprises a suite of enterprise applications that afford the utility functionality on several levels. Central to this architecture are the databases that contain all the collated meter information as well as network (both reticulation and AMI communication) operational parameters.

There are typically three primary players that interact with the meter data management system (MDMS):

- Commercial, who have a vested interest in the revenue management aspects, sustainability of the system, the business intelligence (BI) and report functions relating the customer information and billing.
- Operations are interested in the information emanating from the system operation such as load balancing, voltage and frequency monitoring, rudimentary quality of supply information and demand side load management.
- Network administration, the division responsible for the maintenance and communications aspects of the system, including asset management.

The phased approach

This architecture allows project funding to be allocated in a phased manner. With the deployment of each phase the existing capital investment is secure, it does not need to be removed or made obsolete, and is simply extended to the next phase of functionality as and when required.

It is fundamental to our approach that every stage of the system development adds to and enhances the current investment. Only rarely is it necessary to remove or upgrade installed equipment.

Important notes

An operational challenge that is often overlooked or underestimated is that of the technical competence of the personnel servicing AMI systems. The installer's or technician's capabilities are more suitably coupled with those of conventional metering and network maintenance. They are now called upon to have extended skills in wireless, power line communications (PLC), computers, communications networks and more, often (critically) without the necessary training. This is a recipe for unnecessary problems and customer inconvenience.

No discussion on AMI/smart metering would be complete without mentioning the concerns that have been raised regarding the right to privacy and the management of data gathered regarding the customer's electricity consumption habits. With the system proposed, the granularity of the information gathered will be much lower that the equivalent European or American devices. This granularity still affords the utility the ability to monitor trends and plan network capacity. It is not within the scope of this paper to discuss the legitimacy or otherwise of the arguments. Suffice to say that the debates will continue.

A positive side effect of the implementation of such an AMI/smart metering system is the active asset management and traceability that is a natural outcome of the connectivity.

Conclusion

The approach tabled in this paper affords the utility/supply authority a way of future proofing their system with the sound financial model that makes so many of the world's prepayment electricity metering projects the success they are. The model is both affordable and sustainable.

The solution, using the humble prepayment meter associated with the required network infrastructure and head end software, offers an appropriate and financially sustainable AMI system for low consumption customers. Though the system may not have the high end functionality of a European or American smart grid system, it affords the utility a system that is extensible, affordable and appropriate.

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Contact Tom Phillips, Conlog
Tel 031 268-1111,
phillipst@conlog.co.za

Switching off dangerous electricity circuitry vs. constraints of switching off services

by Deon Louw, Overstrand Municipality

The life of a responsible person, in terms of the Occupational Health and Safety Act (OHSA), General Machineries Regulations (GMR), can sometimes get quite nerve wracking when not only the requirements of the OHSA has to be adhered to but also the requirements of other legislation such as the Promotion of Administrative Justice Act (PAJA). The first deals with safety of people and second deals with the rights of people and sometime these requirements come into conflict.

Fig. 1: Aerial view of the caravan park site.

The paper deals with the unsafe condition of electricity circuitry found in a caravan park within the municipality.

The caravan park is operated by an association which leases the caravan park from the municipality. The lease agreement is several years old and has been extended twice. The association rents this property from the municipality at no charge, but is required to attend to the upkeep of the property as well as the maintenance of all services within the property.

The maintenance of the networks, which include the maintenance of the electricity network, is required by the agreement. Since the municipality decided to look at the redevelopment of this property, it actively inspected the site to determine its condition. It found the property to be seriously lacking in many instances.

Upon inspecting the electricity network it was found that the networks were in a severe unsafe state.

OHSA safety requirements

The inspection of electricity networks is performed as per the requirements of the OHSA and according to the SANS 10142 Wiring Code. In the first round of inspections of the caravan park site, more than 100 cases of unsafe conditions were found.

Responsibility of safety

The first question to answer is to determine who is responsible for this unsafe condition. Regulation 2 of the Electricity Installation Regulations (EIR) states:

2. Responsibility for electrical installations

2 (1) Subject to subregulation (3), the user or lessor of an electrical installation, as the case may be, shall be responsible for the safety, safe use and maintenance of the electrical installation he or she uses or leases.

(2) The user or lessor of an electrical installation, as the case may be, shall be responsible for the safety of the conductors on his or her premises connecting the electrical installation to the point of supply in the case where the point of supply is not the point of control.

(3) Where there is a written undertaking between a user or lessor and a lessee whereby the responsibility for an electrical installation has been transferred to the lessee, the lessee shall be responsible for that installation as if he or she were the user or lessor."

Regulation 2(3) (see previous paragraph) states that this is the responsibility of the lessee if an agreement has been reached in writing. Since the lease agreement carries this clause, the responsibility of the circuitry would in this case fall with the lessee.

Responsibility to act

The next question to answer is to determine what the owner should do if the network or circuitry is found to be unsafe.

The answer is found in the latest version of the OHSA EIR under Regulation 7 in the case where the owner is also the supply authority:

"Electrical Installation Regulations

7(7) If after an inspector, an approved inspection authority for electrical installations or supplier has carried out an inspection or test and has detected any fault or defect in any electrical installation, that inspector, approved inspection authority for electrical installations or supplier may require the user or lessor of that electrical installation to obtain a new certificate of compliance: provided that if such fault or defect in the opinion of the inspector, approved inspection authority for electrical installations or supplier constitutes an immediate danger to persons, that inspector, approved inspection authority for electrical installations or supplier shall ***forthwith*** *take steps to have the supply to the circuit in which the fault or defect was detected disconnected; provided further that where the fault or defect is of such a nature that it may indicate negligence on the part of a registered person, the Inspector, approved inspection authority for electrical installations or the supplier, as the case may be, shall forthwith report those circumstances in writing to the chief inspector."*

Under less dangerous circumstances the association of the caravan park can now be requested to obtain a fresh Certificate of Compliance. It was however found that the circuitry boxes were open and it would be very easy to accidently touch life electrical circuitry. It was also found that the wiring was not

Fig. 2: Pictures of unsafe conditions of electricity circuitry within the caravan park.

Fig. 3: Pictures of unsafe conditions of electricity circuitry within the caravan park.

designed properly and in many cases the wire thicknesses were completely undersized. The network was therefore considered extremely dangerous and could very easily cause electrical shocks. It is therefore clear that the highlighted part of Regulation 7 comes into play, where it is necessary to shut off the electricity power "forthwith". The Oxford dictionary translation of this word is: *"At once; without delay"*.

A further indication of the seriousness of the situation can be found in the OHSA itself under Section 39(2).

"(2) Any employer who does or omits to do an act, thereby causing any person to be injured at a workplace, or, in the case of a person employed by him, to be injured at any place in the course of his employment, or any user who does or omits to do an act in connection with the use of plant or machinery, thereby causing any person to be injured, shall be guilty of an offence if that employer or user, as the case may be, would in respect of that act or omission have been guilty of the offence of culpable homicide had that act or omission caused the death of the said person, irrespective of whether or not the injury could have led to the death of such person, and on conviction be liable to a fine not exceeding R100 000 or to imprisonment for a period not exceeding two years or to both such fine and such imprisonment."

Should a member of the caravan park be electrocuted after this dangerous situation was found, the responsible person would be charged with culpable homicide and can be fined heavily and/or jailed if found guilty.

Promotion of Administrative Justice Act (PAJA)

Upon deciding to switch off the electricity, the municipality was warned by its lawyers that a newer Act, the Promotion of Administrative Justice Act (PAJA), requires that the user of electricity must first have a chance to remedy the faulty condition prior to being switched off. The lawyers claimed that there were many examples in case law to defend this stance. PAJA was established to enact a part of the constitution which determines what rights individuals have as prescribed by the Bill of Rights.

Some extracts from PAJA are repeated below:

"Administrator" means an organ of state or any natural or juristic person taking administrative action;"

"Procedurally fair administrative action affecting any person

3(1) Administrative action which materially and adversely affects the rights or legitimate expectations of any person must be procedurally fair.

3(2)(a) A fair administrative procedure depends on the circumstances of each case. (b) In order to give effect to the right to procedurally fair administrative action, an administrator, subject to subsection (4), must give a person referred to in subsection(1):

(a) adequate notice of the nature and purpose of the proposed administrative action

(b) a reasonable opportunity to make representations;

(c) a clear statement of the administrative action;

(d) adequate notice of any right of review or internal appeal, where applicable; and

(e) adequate notice of the right to request reasons in terms of section 5.

3 (3) In order to give effect to the right to procedurally fair administrative action, an administrator may, in his or her or its discretion, also give a person referred to in subsection (1) an opportunity to

(a) obtain assistance and, in serious or complex cases, legal representation;

(b) present and dispute information and arguments; and

(c) appear in person."

From the above it is clear that in terms of PAJA Section 3, a person has a right to react prior to performing administrative functions.

Dilemma

The responsible person now finds himself in a dilemma. He is required to switch off the electricity due to the severe unsafe conditions that exist, but he may not switch the network off immediately since PAJA prevents him from doing so. He finds himself in a "Catch 22" situation.

It was therefore decided to approach the High Court and request an interim interdict to switch off the network. In the preparation of this interdict, it was still felt that, should someone be injured during the court proceedings, that the OHSA would still be used to act against the responsible person for omitting to act. In order to minimise the risk of prosecution, the situation was formally reported to the Department of Labour.

Section 30(3) of the OHSA states:

"(3) Whenever an inspector is of the opinion that the health or safety of any person at a workplace or in the course of his employment or in connection with the use of plant or machinery is threatened on account of the refusal or failure of an employer or a user, as the case may be, to take reasonable steps in the interest of such person's health or safety, the inspector may in writing direct that employer or user to take such steps as are specified in the direction within a specified period."

It was hoped that an instruction from the chief inspector would override PAJA. The Department of Labour was however satisfied with the route taken and mentioned that if the court delays were too long that they would issue an order to switch off.

It is however not clear whether a precedent exists whereby the instruction of an inspector was considered more powerful than a restriction from PAJA.

Actions taken

The municipality took this matter to the High Court and was awarded an interdict to shut off the electricity and only switch it back on when the necessary Certificate of Compliance was submitted as proof of a safe network.

Possible relief in such a situation

Upon studying PAJA further clauses were discovered:

"Procedurally fair administrative action affecting any person

3 (4)(a) If it is reasonable and justifiable in the circumstances, an administrator may depart from any of the requirements referred to in subsection (2).

(b) In determining whether a departure as contemplated in paragraph (a) is reasonable and justifiable, an administrator must take into account all relevant factors, including:
(i) the objects of the empowering provision;
(ii) the nature and purpose of, and the need to take, the administrative action;
(iii) the likely effect of the administrative action;
(iv) the urgency of taking the administrative action or the urgency of the matter; and
(v) the need to promote an efficient administration and good governance.

(5) Where an administrator is empowered by any empowering provision to follow a procedure which is fair but different from the provisions of subsection (2), the administrator may act in accordance with that different procedure."

In looking at especially Sections 3(4)(b)(ii) and (iv) as well as 3(5) it is found that the administrator may have the power to act immediately should certain circumstances arise, which situation could be urgent enough to take immediate action. Section 3(5) may also indicate that the OHSA would be able to override PAJA when situation of severe danger exist.

Conclusion

With the creation of the constitution many pieces of legislation had to be redrafted to fit into the requirements of the constitution. The Occupational Health and Safety Act (OHSA) was considered to be one kind of act that would not need to be redrafted. The Promotion of Administrative Justice Act, however, may threaten certain actions of the OHSA until persons against whom an action needs to be instituted, had time to react. It may however be allowed to act immediately in certain instances of severe danger to the people. A person not only has the right to be heard, but he also has a right to be kept safe and there would be instances when these rights are in conflict. In any event the risk of being found foul of the Promotion of Administrative Justice Act would probably be less than the risk of falling foul of the Occupational Health and Safety Act when the lives of people are at stake due to a severe dangerous electricity circuit.

Contact Deon Louw,
Overstrand Municipality,
Tel 028 316-3724,
dlouw@overstrand.gov.za

Dangers and hazards of entry into live substations and enclosures

by Barry Gass, ACTOM Protection & Control

This paper looks at the dangers and hazards of entering and working in live substations and enclosures. It looks at some specific examples and incidents and the reasons why persons entering these areas must be trained and deemed competent to work in a substation unsupervised. It looks at the pre-entry requirements, as well as identifying potential or actual dangers and hazards and legal requirements.

There are many dangers and hazards which have to be taken into account when entering live substations and enclosures and many accidents can be avoided if the correct action is taken.

Definitions

Substation: Any building, room or fenced enclosure containing electrical apparatus used for control, distribution and supply of electrical power.

Enclosure: An indoor or outdoor site where electrical apparatus is enclosed and the access locked to prevent unauthorised entry.

Live enclosure: Any room, chamber, yard or enclosed area, in which it is possible for a person, from ground floor level, to make inadvertent contact with, or infringe on safety clearance to live conductors or apparatus or any room, chamber, or enclosed area fitted with an automatic fire suppression system.

Safety clearance: The minimum distance that any part of a person's body or work tool may come close to any bare, unearthed low voltage (LV) conductor or unscreened, unearthed medium or high voltage (MV/HV) conductor.

Section clearance: In the case of any bare live LV conductor and an unscreened live MV/HV conductor, the minimum clearance of the conductor, from any point on or about the permanent equipment, where a man may be required to stand, measured from the position of his feet.

Live chamber: Any chamber, enclosure or any situation in which inadvertent contact with conductors or live parts of electrical apparatus, working at high voltage, is possible from ground floor level.

Prohibited area: An enclosed area, in which live conductors or live parts of electrical apparatus, working at high voltage are accessible, but situated in such a position that inadvertent contact is not possible from ground floor level.

Restricted area: An enclosed area, that is neither a live chamber nor a prohibited area as defined and that is enclosed for the purpose of power system security and the safety of personnel. In both live chambers and prohibited areas, live high voltage conductors are present, but in a live chamber, these live conductors can be touched from ground floor level, whilst in a prohibited area they cannot be touched from ground floor level.

Barrier: Any device that is designed to restrict approach to live electrical apparatus, excavations or other dangerous conditions.

Breaker/circuit breaker: A mechanical switching device, capable of making, carrying and breaking of currents under normal circuit conditions and also making, carrying for a specified time and breaking currents under specified abnormal conditions, such as fault conditions.

Earthed: Connected to the general mass of earth in such a manner as to ensure an immediate safe discharge of electrical energy.

Isolate: To physically disconnect from all possible sources of electrical potential. This can be achieved by opening of links, removing of fuses, racking out switchgear, locking off and placing a danger tag.

Substation pre-entry

Before entering a substation there are certain pre-requisites that should be carried out:

- Check and disable any fire suppression system. This is imperative, as a person's life can be endangered, if the fire suppression system is triggered. There are several systems, but the most common are CO_2 and argonite gas.
- Check there is at least one fire extinguisher present, its condition and when it was last tested.
- Check substation signage and that you have correct personal protective equipment (PPE).
- Before allowing staff to enter the substation, check for any hazardous conditions, give safety talk, explaining dangers, hazards and emergency assembly point.

Entry

After entry, certain things must be done/checked before any work is carried out:

- Sign substation log book and look for any abnormal conditions that could compromise your safety during your task.
- Call control (if there is a control centre) and inform them that you are at the substation and the reason that you are there.
- Conduct a risk assessment (Take 5) and assess any dangerous condition, discuss with staff and obtain their signatures.
- Use your senses, look for hazards, listen and smell for any arcing.
- Mitigate any hazard identified, e.g. barricade any live parts.
- Ensure that no unauthorised person can gain access to the area while work is being carried out.
- Check condition of all the circuit breakers against the drawings.
- Check for any alarms and discrepancies.
- Check first aid kit available.
- Check all equipment and operating tools are available before starting task.
- Check battery tripping unit (BTU) and perform load test.

Risk assessment (Take 5)

A written risk assessment must be conducted before any task is carried out. This is generally referred to as a Take 5, which means that you should take five minutes to stand back and assess the risks before starting the work. This should not be an over complicated or over designed document, as a general risk assessment (code of practice) should already exist and different hazards occur at different work sites, even though the task remains the same.

When any risk is noted, control measures must be put in place – remember the hierarchy of control:

- Elimination
- Replace (method or process)
- Redesign (engineering)
- Separation (isolation or guard)
- Administration (training process)
- PPE

Mechanical	Materials	Electrical	Health	Environment	Other
Slipping	CO_2 gas	Shock	Gas	Air pollution	No supervision
Tripping	Argonite	Burns	Dust	Water pollution	Not trained
Moving machinery	Fire	Explosion	Noise	Ground pollution	Remote control operation
Unsupported loads	Solvents	Switching	Lighting	Spillage	Not complying with rules
Tools	Asbestos	Lock out	Ergonomic	Waste disposal	Complacency
Flying objects	Acid	Isolating wrong circuit	Fumes		Safety clearance
Hot work	Hot metal	Electrocution	Heat		Sharp edges

Severity/consequence						
Weighting	1	2	3	4	5	6
Effect	No impact	Minor	Moderate	Major	Severe	Catastrophic
Explanation	No injury	First aid case	Serious medical treatment	Lost time injury	Fatality; permanent disability	Multiple fatalities

Risk rating = severity x probability

Probability/likelihood						
Weighting	1	2	3	4	5	6
Frequency	Rare	Unlikely	Possible	Likely	Almost certain	Certain
Explanation	Expected never to happen	Can happen once/year	Can happen once/month	Can happen once/week	Can happen daily	Many times a day

Risk rating							
Probabilty	6	6	12	18	24	30	36
	5	5	10	15	20	25	30
	4	4	8	12	16	20	24
	3	3	6	9	12	15	18
	2	2	4	6	8	10	12
	1	1	2	3	4	5	6
	Severity level	**1**	**2**	**3**	**4**	**5**	**6**
	Severity						

Task	Hazard	Risk	Control	Severity	Probability	Risk rating
Signatures of risk assessment team						
Name	**Company**	**Signature**	**Name**	**Company**	**Signature**	**Date**

Table 1: Hazard prompt list.

You will note that PPE is the last resort and not the first line of defence, as many people think.

Examples of dangers and hazards

- Working in a capacitor bank enclosure – close proximity to unscreened, unearthed conductors. A control point earth must be placed at the circuit breaker and a working earth between the harmonic filters and the capacitor bank. The fence surrounding the capacitor bank, as well as any metal structure within the high voltage yard, must be effectively earthed (permanently) to prevent them from becoming alive via induction from the overhead lines.
- Working in an area protected by a fire suppression system – CO_2 gas could be released, and the worker's life would be at risk. Isolate the fire suppression system before working in the area.
- Circuit breaker racked out of the panel and the shutter unlocked, this would allow access to live connections. Lock off all live (potentially live) shutters, busbar and cable.

Example of a Take 5 risk assessment

- Determine the task specific hazards (the hazard prompt of Table 1 can be used as a reference).
- Assess the hazards identified, using the risk rating tables (raw risk). If the risk rating is above 9, then additional controls must be implemented. After additional controls are implemented, a final risk rating (residual risk) must be calculated. If the final risk rating is not below 10, the hazard must be signed off by the responsible person.
- All members of the workforce must be aware of any risks involved and must sign the risk assessment to acknowledge the risk controls to be implemented.

Legal requirements

Notices

Without derogating from any specific duty imposed on users of machinery by the act, the user shall cause notices to be exhibited within and at all designated entrances to the premises, as the case may be, on which generating plant and transforming, switching or linking apparatus are situated. The notices must:

- Prohibit unauthorised persons from entering such premises.
- Prohibit unauthorised persons from handling or interfering with electrical machinery.
- Contain directions of procedure in case of fire.
- Contain directions on how to resuscitate persons suffering from the effects of electric shock.

Provided that this regulation shall not apply to miniature substations (MSS) and distribution boxes, on condition and their access doors can be locked or bolted and that only authorised persons are permitted to open them and work thereon.

Switch and transformer premises

The user shall cause enclosed premises housing switchgear and transformers:

- To be of ample size to provide clear working space for operating and maintenance staff.
- To be sufficiently ventilated to maintain the equipment at a safe working temperature.
- To be, as far as is practicable, constructed to be proof against rodents, leakage, seepage and flooding.
- Where necessary, to be provided with lighting that will enable all equipment, thoroughfares and working areas to be clearly distinguished and all instruments, labels and notices to be easily read.
- To have doors or gates which can be readily opened from the inside, opening outwards.
- To be provided with fire extinguishing appliances, which are suitable for use

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on electrical machinery and which are in good working order: provided that, in the case of unattended premises, suitable fire extinguishing appliances need only be made available at such premises when work is in progress thereon or therein.

- To be of such construction that persons cannot reach in and touch bare conductors or exposed live parts of the electrical machinery.

No person, other than a person authorised by the user, shall enter, or be required or permitted by the user to enter premises housing switchgear or transformers unless all live conductors are insulated against inadvertent contact or are screened off, provided that the person so authorised may be accompanied by any other person acting under his control.

General

All live substations and enclosures should be kept closed and locked to prevent unauthorised entry. Without limiting the responsibility of all employees to comply with applicable laws at all times, it must be ensured that the responsible person shall ensure that all persons working in a substation or enclosure are adequately trained to perform work in a substation.

Categories of persons allowed to enter live substations and enclosures

Competent person: A person who complies with Section A1 (vii) of the OHS Act and is in possession of a competency certificate for the classes of work he is deemed to be competent to work without constant supervision.

Authorised person: An authorised person shall mean a person recommended, in writing, by the electrical engineer or his nominee, and appointed by the designated person to carry out switching, isolating, testing and earthing procedures on MV/HV mains and/or apparatus in liaison with and under the instructions of a control officer as applicable and to issue work permits in respect of such mains and apparatus.

Specifically trained person: Shall mean a person who has been sufficiently trained to undertake certain tasks on or near live electrical apparatus without being under the constant supervision of a competent person.

Non-competent/pre-competent person: Under the direct and personal supervision of competent person.

Duties when entering a live substation or enclosure

- Accept responsibility for all persons assisting him and for non-competent persons personally supervised by him.
- At all times exercise proper control over these persons and issue explicit and proper instructions and obtain confirmation that the instructions are understood.
- Ensure that only necessary persons enter a live substation, yard or enclosure.
- Ensure that all persons under his control are warned of the danger of inadvertent contact with live conductors and apparatus.
- Be responsible after entering that no unauthorised person can get access.
- Be responsible for the barricading and/or demarcating of any doors or gates left open during the work.
- Erect temporary barriers to prevent persons coming into inadvertent contact with or encroaching safety clearance to live mains/apparatus.
- On leaving the substation or enclosure, be responsible for ensuring that the door or gate is locked and that the key is removed.
- Where adjacent equipment is live, delimit the section which is set aside for work to be carried out by the use of barriers arranged so that safety/section clearances are maintained.
- Delimit the area at ground floor level and the structure or apparatus on which the work is to be carried out.
- When it is impracticable to provide adequate barriers and screens, arrangements shall be made for a competent person to watch continuously the men at work to ensure that they incur no risk.
- Use of portable ladders and long objects where there are exposed live conductors: Portable ladders and other long objects shall not be used without the permission of an appointed person who shall define the conditions of use to the person-in-charge of the work. The movement and erection of such ladders shall then be carried out only under the direct supervision of the person in charge of the work and when moved at ground level they shall be carried only in a horizontal position and as near the ground as practicable.

OHS Act (1993) Section 8: General duties of employers

Every employer shall provide and maintain, as far as is reasonably practicable, a working environment that is safe and without risk to the health of his employees.

Without derogating from the generality of an employer's duties under subsection (1), the matters to which those duties refer include in particular:

- The provision and maintenance of systems of work, plant and machinery that, as far as is reasonably practicable, are safe and without risks to health.
- Taking such steps as may be reasonably practicable to eliminate or mitigate any hazard or potential hazard to the safety or health of employees, before resorting to personal protective equipment.
- Making arrangements for ensuring, as far as is reasonably practicable, the safety and absence of risks to health in connection with the production, processing, use, handling, storage or transport of articles or substances.
- Establishing, as far as is reasonably practicable, what hazards to the health or safety of persons are attached to any work which is performed, any article or substance which is produced, processed, used, handled, stored or transported and any plant or machinery which is used in his business, and he shall, as far as is reasonably practicable, further establish what precautionary measures should be taken with respect to such work, article, substance, plant or machinery in order to protect the health and safety of persons, and he shall provide the necessary means to apply such precautionary measures.
- Providing such information, instructions, training and supervision as may be necessary to ensure, as far as is reasonably practicable, the health and safety at work of his employees.
- As far as is reasonably practicable, not permitting any employee to do any work or to produce, process, use, handle, store or transport any article or substance or to operate any plant or machinery, unless the precautionary measures contemplated in paragraphs (b) and (d), or any other precautionary measures which may be prescribed, have been taken.
- Taking all necessary measures to ensure that the requirements of this Act are complied with by every person in his employment or on premises under his control where plant or machinery is used.
- Enforcing such measures as may be necessary in the interest of health and safety.
- Ensuring that work is performed and that plant or machinery is used under the general supervision of a person trained to understand the hazards associated with it and who have the authority to ensure that precautionary measures taken by the employer are implemented.
- Causing all employees to be informed regarding the scope of their authority as contemplated in section 37 (1) (b).

Section 14: General duties of employees

Every employee shall at work:

- Take reasonable care for the health and safety of himself and of other persons who may be affected by his acts or omissions.
- As regards any duty or requirement imposed by his employer or any other person by this Act, co-operate with such an employer or person to enable that duty or requirement to be complied with.
- Carry out any lawful order given to him, and obey the health and safety rules and procedures laid down by his employer or by anyone authorised thereto by his employer, in the interest of health or safety.

- If any situation which is unsafe or unhealthy comes to his attention, as soon as practicable, report such situation to his employer or to the health and safety representative for his workplace or section thereof, as the case may be, who shall report it to the employer; and if he is involved in any incident which may affect his health or which has caused an injury to himself, report such incident to his employer or to anyone authorised thereto by the employer, or to his health and safety representative, as soon as practicable, but not later than the end of the particular shift during which the incident occurred, unless the circumstances were such that the reporting of the incident was not possible, in which case he shall report the incident as soon as practicable thereafter.

NRS 040-3:1995

4.7.9 No switching while work is in progress in a live chamber or enclosure:

Should any switching, other than emergency switching, at any station, on apparatus in a live chamber or live enclosure in which inspection or maintenance work is in progress, all persons shall be withdrawn from the chamber or enclosure until such switching has been completed.

4.8.2 Emergency switching:

Any person is authorised to carry out emergency switching. When emergency switching has been carried out the control officer should be informed as soon as possible.

Please note that emergency switching refers to the opening only of switchgear for the two following conditions: in order to prevent injury to a person or damage to equipment.

Incidents

Incident 1

Two competent electricians were working in a live 11 kV substation containing oil circuit breakers (OCBs) when a fault occurred. Both the circuit breaker feeding the fault and the incoming circuit breaker failed to trip. The upstream protection was slow in operating and the circuit breaker feeding the fault exploded, killing both of the electricians in the substation. In the ensuing accident investigation it was found that the DC supply at the substation had failed.

It is, therefore, recommended that when working in a substation the batteries and charger are checked and a load test carried out if facilities exist.

Incident 2

A fault developed in an outdoor voltage transformer (VT) in a live yard. The VT exploded, causing a fire and extensive damage to equipment. Shrapnel was hurled over 20 m away, embedding itself in a wall. The investigation revealed that the VT developed an internal fault and exploded. Fortunately, there was no one present in the yard at the time of the incident, however, it can be seen that anyone in the yard at the time of the explosion would have been in great danger.

Incident 3

This incident also involved an OCB which exploded; fortunately there was no one in the substation at the time. The force of the explosion was such that it blew out a section of the substation brick wall, hurling bricks some distance away. The investigation revealed an internal fault inside the circuit breaker.

Incident 4

A fault occurred on a circuit breaker panel in a 33 kV substation. The force of the explosion blew the breaker out of the panel over 10 m away. Anyone working in the substation at the time would have been injured, had they been near the breaker at the time.

Incident 5

Two protection technicians had to conduct current transformer tests on an 88 kV transformer situated at a power station. Permission was obtained from control to do the tests. The gates to the 88 kV yard were open (the lock was damaged and unable to be locked). The technicians made their way to the correct transformer and checked that the links feeding the the transformer were open (however, there was a double busbar and the other set of links were closed and the transformer was alive). Assuming the transformer was dead they decided to discharge the conductors before climbing on top of the transformer using a portable earthing lead. As soon as the lead came close to the line there was a flash over and an explosion. The two technicians both received arc flash burns to the face and hands and injury to their legs jumping down from the transformer. An investigation revealed the following:

- Control incorrectly gave permission for work to be carried out.
- The gate to the 88 kV yard was open and could not be locked.
- Both of the technicians were not trained on high voltage and could not identify the hazards and follow the correct procedures and were, therefore, not competent to enter the yard by themselves.
- No testing or earthing had been carried out.
- No work permit had been issued.
- No risk assessment had been conducted.

Incident 6

A new switchboard was being installed at a substation and a temporary 11 kV supply was taken from a spare circuit breaker, on the existing feeder board, to the incoming panel of the new switchboard. Once the permanent supply was installed and ready for connection, it was decided to leave the temporary cable in as a back-up supply. In order to do this, the spare breaker on the existing feeder board was isolated and locked out and the cable on the new switchboard was disconnected and left open at the back of the panel.

A contractor, completing his punch list, was numbering cables. He opened the substation door and left his non-competent worker inside to complete the list. The worker walked around the back of the switchgear, where he trod on the exposed cable, causing ionisation to earth, which caused a phase-to-phase fault. The flash caused by this fault generated third degree burns to 80% of his body and he died in hospital four days later. The investigation revealed that the circuit breaker on the existing feeder board feeding this cable had tripped on earth and phase-to-phase fault. Who racked the circuit breaker in and closed it is not known. Why the ends of the temporary cable had not been removed from the switchgear on the existing feeder board and starred out and earthed on either side is not known.

Looking at all six of the above incidents it is clear that a risk assessment needs to be conducted when entering these areas, to identify the hazards, put in place remedial measures and inform workers of dangers and hazards present.

Conclusion

From the above, one can see that it is not only a legal requirement for all staff entering a substation to be trained (or under the direct and personal supervision of a competent person), it is necessary to prevent injury or even death, therefore, training is essential.

So often, at the workplace, we hear prodóction before safety, not safety before production.

No operation or urgency of service can ever justify endangering the life of anyone. Before doing any job, ask yourself this question: Would I let my 16 year old son or daughter do this job? If not why, should I be doing it? Or expect anyone else to do it?

References

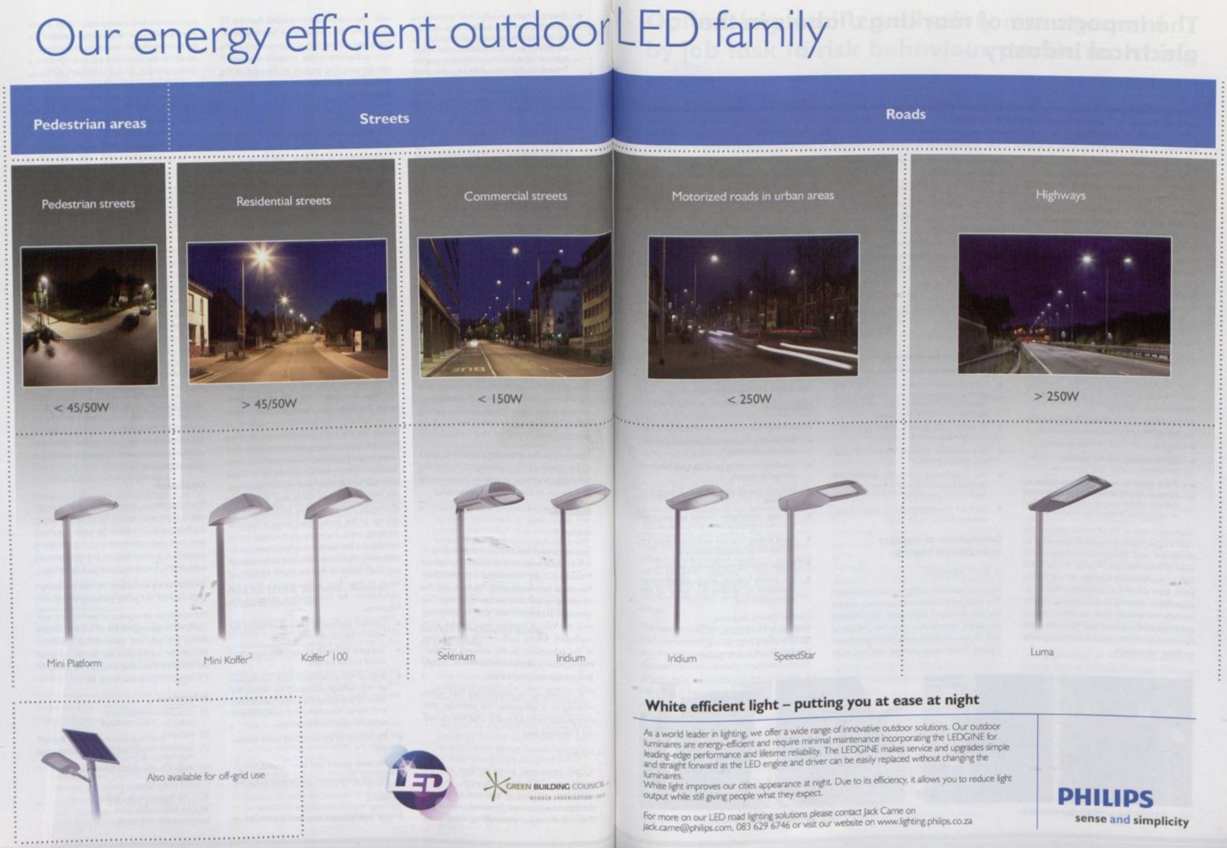
[1] Occupational Health and Safety Act (1993) (OHSAct)

[2] NRS 040

[3] Operating Regulations for High Voltage Systems (ORHVS)

[4] Abaqulusi Municipality Safety Rules

Contact Barry Gass,
ACTOM Protection & Control,
Tel 011 820-5111,
barry.gass@actom.co.za



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sense and simplicity

The importance of markings/labels in the electrical industry

by Dennis Mokoala, Polokwane Municipality

Wrong labeling/markings were identified as one of the causes of industrial accidents where property is damaged and/or people are injured or have lost their lives.

Labeling/marking is a legislative requirement to be performed in every electrical installation made. It is stipulated in SANS 0142 and forms part of the visual inspections to be performed upon completion of an electrical project, or after completion of changes performed from an existing installation. During maintenance this is normally not done, especially where the custodian has full time staff who perform maintenance. This will thus end up sacrificing the safety of the same maintenance team. The feeling is that the supervisor will make sure that whatever is done in the network is done in the proper and compliant manner, which in practice is not true.

To label means to attach to an object a mark to indicate its contents or ownership. To mark means to spot or scratch a surface. This brings us to the characteristics of markings/labels. A label or mark must be:

- Permanent e.g. scratched or engraved on a surface.
- Legible.
- Able to sustain normal weather conditions.
- If the label is on a separate piece of material, it must be fixed with a permanent material where one will need to use a tool or lubricating material to remove it.

Markings/labels in the electrical network are used to give information about apparatus or equipment used. Markings on cables can be used to show the type of cable, the size, the type of equipment it supplies as well as the point from which it is connected. On mini-substations, marking and labeling is used to indicate the primary and secondary supply point in case of ring feed, and the load as well. For the sake of this paper, I will concentrate on these two aspects.

Dangers of wrong or inadequate labeling/marking

- Unplanned power outages
- Damage to equipment and/or property
- Personnel injury or loss of life
- Loss of income
- Disturbed service delivery
- Unpleasant situations for clients
- Funds for redoing the work
- Loss of information
- Work stoppages
- Waste of materials e.g. wasted dough during baking
- Loss of business

Labeling/markings during maintenance or repairs

- During maintenance and repair work, less attention is placed on compliance. In most cases the main issue becomes the time to be taken to restore the power.
- In many cases, labeling/marking is done on a temporary basis, if at all.
- Any available labeling material is used e.g. marking pens.
- No compliance certificate is normally provided especially where the client does repair work personally.
- Lack of knowledge or a "don't care" attitude during repair work.

Consequences of improper or inadequate labeling

At Sigma substations

We were busy with replacing old switchgear. The label on the old switchgear was left on the old damaged switchgear. The incident happened immediately after the change of shift. There was a ring main switch which had tripped. The foreman ordered switching to be made after the fault on the line was identified and repaired. The old damaged switchgear was then made live, switching onto a fault. The switchgear exploded. Luckily there were no injuries.

At Bok Street mini-substation

The mini-substation caught fire but the ring main switch tripped at the substation. The fault was identified as being the termination on the mini-substation that caused the fire. During power restoration, the same cable was switched on due to wrong labeling. The mini-substation exploded. It was during the night and only electricians who were on duty were around, and they had a good clearance from the mini-substation. Fortunately the people who were close by had been given enough space from the mini-substation.

Conclusion

Lessons learned:

- We nearly lost a substation due to improper labeling.
- Labeling/markings must be updated and verified timeously.
- Nobody should work while switching is in progress.
- Unused switchgear should be removed from the substation once no longer in use.
- Signs stating "Do not switch on" must be placed on all unused breakers.
- Proper labeling must always be used.
- We nearly lost an employee who was supposed to remove the cover of the termination box.

Contact Dennis Mokoala,
Polokwane Municipality,
Tel 015 290-2772,
dennism@polokwane.gov.za

Fig. 1: Sigma substation.

Fig. 2: The mini-substation in Bok street.

Optimising health and safety management by job task to risk behaviour profile matching

by Dr. WJ du Toit, SAFTEK

Organisations in the electrical engineering environment do not always acknowledge risk factors related to specific employees' predisposition for high risk taking behaviour that could have a negative impact on their activities. Rather, organisations concentrate on structuring their engineering environment and activities to comply with health and safety (H&S) legislation in the belief that such compliance could afford a guarantee against incidents.

The unfortunate reality is that the individual has the capacity, intentionally or unintentionally, to cause the greatest impact on H&S statistics.

The approach in managing probabilities in equipment and reticulation failures are to optimise design criteria with a higher factor of safety in managing fault conditions in order to render such equipment safe. The maintenance and installation of electrical engineering activities have always had a close relationship with H&S, more so than for other engineering activities, due to the high impact failures that such systems have on plant and equipment and the greater possibility for human fatalities. However, the input from management has always been to provide policy and procedures that must be followed exactly. Unfortunately, in the electrical engineering environment, due to a mostly continuous altering work environment, fixed procedures do not hold as too much reliance is placed on the individual's competence and insight for correct evaluation and decision making.

According to Navare (2003), focus on human behaviour rather than on procedures is not a new feature of risk management. In 1959, Heinrich introduced two views of risk management and control: the engineering view and the human relations view. The former related to the physical causes of accidents while the latter required human action to be taken into consideration as most of the accidents recorded were related to human failure.

The need for a different approach to managing H&S in an electrical engineering environment and the acknowledgement of the impact that incorrect decisions made by employees, due to differences in individuals' perception of risks, is indicative of the impact of electrical incidents. The need is further emphasised by the unique environment of electrical engineering and the differences in competency requirements for risk identification in relation to human sensory and heuristic knowledge gained by experience. The influence of a diverse cultural society of South Africa, and the impact that such cultural paradigms have on influencing individual decision-making further require a different approach to managing H&S.

Undesirable human behaviour is a major contributing factor in accident causation. Such undesirable risk taking behaviour should be managed and taken into account by H&S management systems, but the unfortunate reality is that in most instances provision is made only for the management and control of environmental factors, and not the impact of human behaviour.

Although human error cannot be completely eliminated, it should be identified and correctly managed according to each individual's risk taking profile. The reason people decide to take certain risks under certain conditions and the effect these have on H&S management systems is a key component to managing organisational risk exposure.

A model that includes methods to identify specific risk taking behaviour profiles of individuals and to manage such characteristics to limit the negative impact, with improvement in incident statistics, is required. A model of risk behaviour profile matching to high risk task is presented.

Literature overview

Human risk taking behaviour

Human behaviour relates to factors affecting psychology, sociology, and the anthropology of humans. Individual human factors that affect decision-making in taking or rejecting risks relates to both the external socio-environment as well as the individual's beliefs. Mahadevan (2009) indicated that human behaviour patterns are the chains that still bind us from achieving our goals. Mahadevan (2009) states that "more than a hundred years ago it was said that we have nothing to lose but our chains. Now the chains are, of course, not of our hands but the chains of our brains".

According to Stranks (1994), human behaviour patterns affecting H&S are defined as a wide range of issues which include, but are not limited to:

- The perceptual, physical and mental capabilities of individuals
- The influence of equipment and system design on such persons' performance
- The organisational characteristics that influence such individual behavior

Human risk behaviour is dependent on various parameters such as the differences in the behaviour of genders and the view of risk to oneself and to others. Women have been found to show a greater difference between personal and general risk than men, reducing the often quite large gender difference in ratings of general risk (Sjöberg, 2002). People are usually more concerned about the risks to others than to themselves (Sjöberg, 2002).

To determine what motivates an individual to either intentionally or unintentionally behave in a certain risk taking manner, there is a need to understand human motivational analysis. According to Domingo and Santiago (2008), the optimum amount of risk a person is prepared to take depends not only on uncertainty, but also on the person's risk preferences.

When in threatening situations, people behave to protect themselves psychologically by denying unpleasant situations. Psychological denial is very common during the first moments of a fire when people find reassuring and benign explanations for the cues they see, smell, and hear. Avoidance explains why a person delays recognising the threat and spends long minutes ignoring the situation (Mitchell, 1999).

The role of unintentional actions in incidents, or as Sigmund Freud names it, "unconscious intent", is a factor contributing to incidents that are not always taken into account. According to McClelland (1985) Freud's early work showed that peoples' motives for what they do in everyday life are often unconscious. Human risk behaviour thus involves more than mere action or impulses.

The application of human behavioural factors requires an understanding of human capabilities and fallibilities so as to recognise the relationship between work demands and human capacities when considering human and system performance. The aim is to eliminate or reduce the chance of adverse behavioural outcomes which can lead to harm through accidents or chronic exposure to conditions adverse to health (Bellamy, Geyer and Wilkinson, 2008).

No person intentionally behaves in a manner that would cause him injury but rather takes a risk based on a personal estimation or calculation that no harm will befall him. Individual risk-taking behaviour is influenced by a person's psychological and physiological make up, as well as environmental influences. The behaviour of a group of people taking risks is influenced by the way individuals in the group transfer their beliefs to the group as a whole.

Individual risk taking behaviour is affected to the extent that the individual's abilities allow him certain actions. Navare (2003) indicated that behavioural aspects transcend all boundaries, in that we seek to manage the initiative and ability of those involved or affected by incidents, irrespective of boundaries.

Human H&S behaviour standards, incorporated in various legislation, have the aim of creating procedures that will limit or prevent any unhealthy or unsafe acts. Smallwood (2000) states that underwater diving accidents occurred because divers were so well trained in procedures that obvious, simple, and immediate solutions were forgotten or ignored. Professionalism, when superseded by a system, clouds an individual's initiative and judgment. The effect of standards in contributing to incidents by creating confusion and limiting "common sense" is not always taken into account in legislation. The initial approach to H&S management was that sound controls and management of the physical environment could override human incompetence.

If risk management is one of behavioural management then it is the behaviour which is the risk that needs to be managed (Navare, 2003).

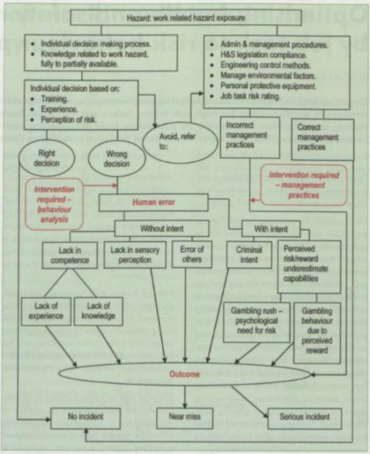


Fig. 1: Basis for a model that will address risk behaviour.

Perception of risk

Sjöberg (2002) indicates that risk perception is not a question of emotion. The judgement of the size of a risk is an intellectual one, having only a weak relationship to an emotional dimension such as worry. With non-professionals the nature of risk perception is greatly affected by the level of their self-esteem, (i.e. how competent they consider themselves and how they estimate their own skills). Those who are uncertain and do not feel competent generally overestimate risk (Verez, 2009).

Behaviour is linked to perception of risk. Gstraunthaler and Day (2008) found that the greater the individual's perception of risk the higher the likelihood of action to reduce that risk. They proposed that the state of mind and emotional condition affected the individual's risk taking behaviour.

This is supported by evidence that happier decision makers tend to be less risk seeking in situations where a meaningful loss may diminish their positive emotional state (Gstraunthaler, 2005).

How we evaluate, classify and value risk affects our decisions to ignore, take action or avoid the circumstance a risk environment poses (Aucote and Dahlhaus 2010). Sjöberg (2002) found that high-risk takers were mostly found among those who had the lowest level of education. In the context of construction workers with basic education only, it is assumed that risk taking behaviour will predominate. This correlation between competence and risk taking behaviour indicates lack of knowledge rather than intent on risk taking.

The cause of accidents due to human error

Factors contributing to incidents

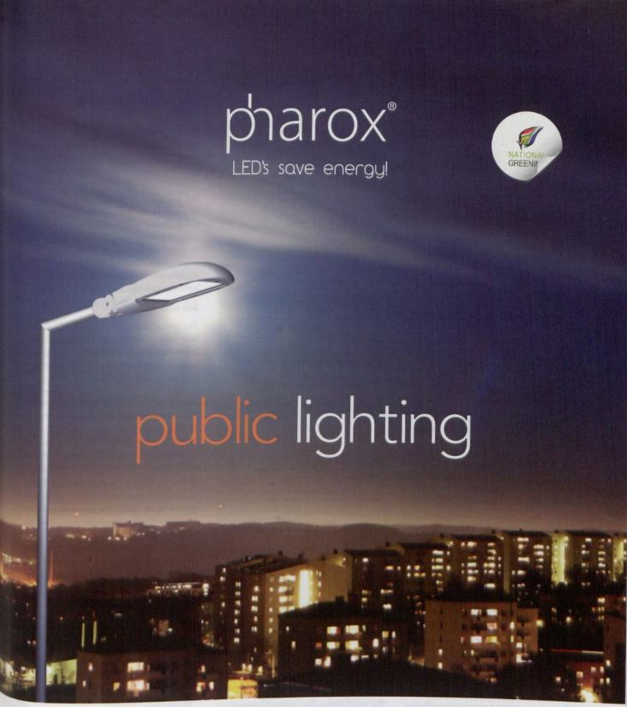
The impact of individual risk taking behaviour, intentionally or due to negligence, is one of the main contributing factors of incidents. If we analyse the impact and cause of human errors, socio-technical failures are inherent to the core of human performance failures and indirectly the cause of accidents. Bjerkan (2010) indicates that the traditional view of industrial accidents reflects that accidents are caused by technological as well as individual human failures. Accidents are caused by a dynamic interaction of factors in the social and physical environments, that is, characteristics of the individual and the organisation as well as technical forces that have an influence in such environments.

Managerial approach to incorrect behaviour

Training is perhaps the most effective aspect that can influence and alter risk taking behaviour and would be the most valuable tool that organisations can use to influence incident statistics. Challenges in training occur because even when large amounts of money are allocated towards H&S training, managers often do not consider whether or not training procedures and programmes are appropriate for the people being trained. The ideal opportunity for management intervention, as indicated in Fig. 1, would be to be pro-active before the individual acts on incorrect high-risk decisions made.

An alternative approach to managing high risk behaviour

Alternative interventions to training in addressing risk behaviour would be to match and optimise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Application of job task to individual profile matching		Acceptability
Individual risk behaviour profile	Job task risk profile	
Low	High	Optimum
	Average	Optimum
	Low	Optimum
Average	High	Acceptable
	Average	Optimum
	Low	Optimum
High	High	Unacceptable
	Average	Unacceptable
	Low	Acceptable

Fig. 2: Acceptability levels of job task to individual profile matching.

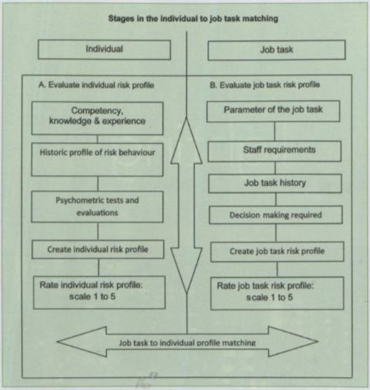

Fig. 3: The model: job task to individual profile matching.

individuals to correct tasks by using effective HR expertise assistance and technical job risk requirement knowledge. The probability for risk taking behaviour would be limited in that high risk behaviour individual decisions to act correctly are not always a clear choice, especially when the individual is exposed to unknown scenarios or where immediate decisions should be made by the correct selection of individuals with capacity. Due to their competence to make appropriate decisions when exposed to high risk tasks, incidents would be limited.

The optimum scenario is to have the right tools for the right task or, in other words, the right person for a specific task. Such matching should have the competence of the person and the quantitative value of the task in mind.

Addressing risk behaviour

Stages of H&S management required due to risk behaviour are outlined in Fig. 1.

The aim of a risk rating for a job task match to an individual profile is to obtain a mathematical index that will reflect the risk factor associated with each job task and the individual's risk profile that will afford the capacity for matching such profiles according to the proposed model in Fig. 1.

Job task-to-individual profile matching

The rating index aims to quantify the values related to job tasks and individual profiles where such mathematical index will give better matching of the different profiles as presented in Fig. 2.

The job task-to-individual profile matching as shown in Fig. 2 shows that optimum job-to-individual profile matching occurs with an index of low individual risk-taking behaviour to a high risk job task profile matching. The unacceptable matching would pose high risk in profile matching of high individual risk-taking behaviour to a high or average risk job task.

Job task matching

The model proposed in Fig. 3 of job risk task-to-behaviour profile matching, if implemented, provides an ideal opportunity for organisations to lower incident statistics.

Rating index for job task

The rating index for job tasks, indicated in Fig. 4, concentrates on four aspects according to parameters and training required: staff requirements and physical capability, the history of job task performance and the experience required for decision-making.

The higher the risk involved in the task, the more stringent the requirements must be. The process of recruitment begins when new jobs are created in the organisation or when an existing designation becomes vacant due to transfer or retirement. The rating index can be obtained by the following formula:

$$RI_i = (P_i \cdot w) + (S_i \cdot w) + (E_i \cdot w) + (H_i \cdot w) \quad (1)$$

where:

RI_i: Rating index for job task.

P_i: Parameters and training required for job task.

S_i: Staff requirements and physical capability for job task.

E_i: Experience required for decision-making for job task.

H_i: History of job task performance.

w: Weight allocation.

Eqn. 1 provides a rating index for job tasks according to specific risk attributes of the job task where the value of the indexes will indicate the risk involved in performing a specific job task.

Rating index for individual risk behaviour profiling (RI)

The rating of the individual risk behaviour profile is the sum of competency of the individual plus the history of risk-taking behaviour including task performance plus the outcome of specific psychometric tests.

The rating index for individual risk behaviour profiling (RIi) is determined by:

$$RI_i = (H_i \cdot w) + (P_i \cdot w) + (C_i \cdot w) \quad (2)$$

where:

RI_i: Rating index for individual risk behaviour profile.

H_i: History of individual incidents related to job task.

P_i: Psychometric testing of individual.

C_i: Competency of individual.

w: Weight allocation.

The weight allocated to each variable, as indicated in Fig. 5, depends on the importance afforded due to the specific work environment.

Variable	Environment	Weight allocation
P: Parameters and training required	High competency demand	High
	Average competency demand	Medium
	High competency demand	Low
H: History of job task performance	High competency demand	High
	Average competency demand	Medium
	High competency demand	Low
S: Staff requirements and physical capability	High competency demand	High
	Average competency demand	Medium
	High competency demand	Low
E: Experience required for decision making	High competency demand	High
	Average competency demand	Medium
	High competency demand	Low

Fig. 4: Weight allocations for variables related to specific job tasks.

Variable	Environment	Weight allocation
H_i: History of incidents related to Job task	High competency demand	High
	Average competency demand	Medium
	High competency demand	Low
P_i: Psychometric testing of individual	High competency demand	Allocation determined by psychometric test developer
	Average competency demand	
	High competency demand	
C_i: Competency of individual	High competency demand	High
	Average competency demand	Medium
	Low competency demand	Low

Fig. 5: Weight allocation for variables of risk behaviour profiling.

Conclusion

The variability in risk that human behaviour poses to organisations should be taken into account and managed in ways that can quantify the risk profiles of individuals. H&S management can no longer be seen as the management of environmental factors only, but must also take into account the critical component of individual behaviour. Such components relate to the capacity of influencing incident statistics, due to personal decisions made according to beliefs and psychological profiles. Organisations need to employ ongoing assessment processes in working towards and achieving set goals and targets. Such targets can only be achieved from lessons learned by previous incident experiences (Al-Qudah and Al-Momani, 2011).

The model proposed in Fig. 3, that of job risk task to behaviour profile matching, if implemented, provides an ideal opportunity for organisations to lower incident statistics.

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Contact Willem du Toit, SAFTEK,
Tel 044 873-2235, wdutoit@saftek.co.za

Low loss distribution transformers in a South African context

by G Stanford, G Jones and S Whiting, Powertech Transformers

This paper provides an overview of the importance of losses in a distribution transformer. Current distribution transformer loss specifications are reviewed and an evaluation of the capitalisation formula is given with regards to four utilities.

South Africa's power stations are under extreme pressure. In the last two decades there has been a continuous increase in load demand without a significant increase in generation capacity. Relief of this pressure can be done through building new power stations, which is a lengthy and very costly exercise. This in effect will see energy tariffs increase drastically in the short to medium term in an attempt to recover these costs. Avoiding the cost of this upgrade is not possible but the costs can be controlled by using electricity effectively and efficiently. Although the cost of new power stations may be inevitable, using energy more efficiently in the interim will allow for the lead time to build the generation capacity required. In an attempt to curb the maximum demand on the network, energy users have been requested to use electricity with due caution and the network efficiency is being reviewed.

There are unavoidable losses on the country's electricity network. Up until recently losses were of insignificant value due to low energy costs and sufficient generation capacity. Statistics reveal that losses occurring on transformers found in generation, transmission and distribution networks account for one third of the total electricity network losses. Therefore, more efficient transformers could produce: real cost savings for consumers, an effective increase in the capacity available and relief of some of the pressure on generation capacity.

The reduction of load on current coal fired generators will also effectively reduce the greenhouse gases produced by these types of generation until renewable types of generation can be installed.

Considering the tariffs and viability of renewable generation, the development of low loss transformers will be necessary to ensure that the power generated by renewable generators is delivered to the network efficiently.

Review of distribution transformer specifications

In order to establish where the SA industry is with respect to losses in transformers it is necessary to look at the current transformer loss specifications. Most users specify or base their specification on the SABS 780 (South African Bureau of Standards, 2009, Edition 4) maximum component losses.

Losses are broken down into:

- *No-load loss (NLL)*: "The active power absorbed when a rated voltage (tapping voltage) at a rated frequency is applied to the terminals of one of the windings, the other winding or windings being open circuited" and
- *Load losses (LL)*: "The absorbed active power at a rated frequency and reference temperature (see 11.1), associated with a pair of windings when rated current (tapping current) is flowing through the line terminals of one of the windings, and the terminals of the other winding are short circuited" as defined in IEC 60076-1.

The biggest users of distribution transformers in the South African market are Eskom, large municipalities, mines and large industry. These users usually have their own distribution transformer specifications which use the SANS780 specified losses as an allowable maximum loss.

In addition to these maximum component losses, a capitalisation formula is sometimes specified as an incentive to the transformer supplier to offer transformers that are optimised in line with the cost of electricity applicable. A cost is given for each component loss in rand per kilowatt (R/kW) factor.

These factors give the cost of the energy lost in the transfer of energy from one voltage level to the next in the transformer. The difference between the two component costs, load and no load loss, is the loading factor. This is because no load losses are there as long as the transformer is energised where the load loss is proportional to the loading on the transformer.

The loss costs, from the factors multiplied by the component losses, are added to the sales price of the offered transformer to calculate the associated lifecycle cost of the loss.

The typical formula is as follows:

$$\text{Total cost} = A + F_{NL} \times P_{NL} + F_L \times P_L$$

where:

A = Cost of purchasing the transformer, R

P_{NL} = No-load losses, kW

P_L = Load loss, kW

F_{NL} = No-load loss factor, R/kW

F_L = Load loss factor, R/kW

Each utility has different circumstances that affect their cost of electricity. For example how close the utility is to generation determines the amount of the cost that can be attributed to transmission, distribution and markup costs.

A utility may decide to include the cost of generation replacement based on the load forecast plan. This will show the utility if the cost of reducing losses is less than that of building more generation. This being the case the investment should be in reducing losses of transformers rather than investing in generation. For this reason four different utility cost factors are to be considered with varying cost factors. Where not specified, utilities have based cost factors on a life span of 25 years.

Utility 1 uses the following cost factors in their capitalisation calculations:

				Utility 1	Utility 2	Utility 3	Utility 4
Efficiency SANS 780 = 98,04%	NLL kW 0,3	LL kW 1,7	Sales PU 1	TCO PU 1	TCO PU 1	TCO PU 1	TCO PU 1
98,12%	0,22	1,7	1,03	0,96	0,94	0,94	0,93
98,26%	0,07	1,7	1,74	1,27	1,11	1,1	0,99
98,37%	0,08	1,6	1,69	1,23	1,07	1,06	0,95
98,43%	0,25	1,4	1,41	1,15	1,06	1,05	0,95
98,53%	0,14	1,4	1,48	1,12	1	0,99	0,89

Fig. 1: Cost comparisons of various efficiency transformers.

F_{NL} = 31 200 R/kW

F_L = 6700 R/kW

Utility 2 uses the following cost factors in their capitalisation calculations:

F_{NL} = 56 430 R/kW

F_L = 11 789 R/kW

Utility 3 uses the following cost factors in their capitalisation calculations:

F_{NL} = 58 062 R/kW

F_L = 12 529 R/kW

Finally, Utility 4 specifies loss factors with the following breakdown:

F_{NL} = 0,52 R/kWh x 24 hours x 365 days x N years R/kW

F_L = 0,52 R/kWh x 24 hours x 365 days x N years x Load factor R/kW

where for transformers:

Up to 200 kVA the load factor = 0,3.

315 kVA to 500 kVA the load factor = 0,4.

Above 500 kVA the load factor = 0,6.

Up to 315 kVA the life N = 20 years.

Above 315 kVA the life N = 25 years.

giving:

Up to 200 kVA	F_{NL} = 91 104 R/kW
	F_L = 27 331,20 R/kW
315 kVA	F_{NL} = 91 104 R/kW
	F_L = 36 441,60 R/kW
500 kVA	F_{NL} = 113 880 R/kW
	F_L = 45 552 R/kW
800 kVA up	F_{NL} = 113 880 R/kW
	F_L = 68 328 R/kW

The comparison above confirms the cost of energy is different for different consumers. The specifications also vary in complexity: from those that just specify maximum SANS 780 component losses to those that take into account life cycle time and load factors.

So does the general approach of evaluating the life cycle cost with the use of a capitalisation formula work or should one just work with maximum losses as has been the case in past?

Evaluation of the use of the capitalisation formula

To simplify the analysis and evaluation of the capitalisation formula method, we shall consider 100 kVA 11 kV transformers of different loss level. SANS 780 specifies no load losses of 300 W and load losses of 1700 W. The SANS losses will serve as a maximum losses or lowest efficiency design for this evaluation. Costs have been converted into per unit (PU) values using the SANS costs as a base value. The component losses are converted to efficiency so as to normalise the effects of both components.

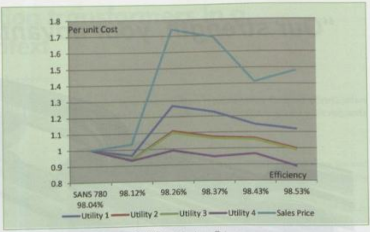

Fig. 2: Per unit cost vs. efficiency.

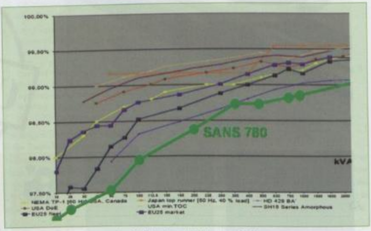

Fig. 3: SA benchmark (Geldenhuys, 2009).

A number of designs are compared with varying efficiency, sales price and total cost of ownership (calculated with the different capitalisation formulas) in Fig. 1 and Fig. 2.

It can be observed that the sales price increases as the efficiency of the transformer improves.

This is attributed to the use of more conductor area, more core area, better materials and improved manufacturing techniques needed to ensure the transformer loss is reduced.

The spike in sales price and the capitalised costs at 98,26% can be attributed to a technology change to amorphous type transformers. A possible reason why this amorphous example shows such a spike in costs is that it is imported technology as opposed to the locally manufactured grain oriented designs that dominate this analysis. Since amorphous transformers are generally designed to Chinese or Indian specifications there is an additional cost associated in introducing new designs in amorphous technology.

A second amorphous quote was obtained to try and investigate the reasons for the spike mentioned above. The quote was for a Chinese specification transformer (the 98,37% design), similar in size and specification to that in the comparison. The quote proved to be slightly more cost effective. This proves that the cost in changing designs to meet the South African specification does not affect the cost of importing amorphous technology greatly. Costs for this technology will have to be reduced by cutting out importation costs.

It can also be noticed that for Utilities 1, 2 and 3, the total cost of ownership calculations indicate the 98,12% efficiency design is the cheapest total cost of ownership.

If the main focus of design evaluation is to reduce losses without concern for the sale price but not increasing the total cost of ownership from the SABS 780 value, then the 98,53% efficiency design could be motivated for in Utilities 2, 3 and 4. This course of action would assume that the finances are available for the sole price of 48% more than the SABS 780 transformer cost. As reducing losses may be the ultimate goal of the utility, what can be done to drive down losses of distribution transformers?

Further loss improvement

To further reduce losses, more materials can be put into the design thus increasing costs and the size of the transformer. Ideally the utility would not like the transformer to grow in size, weight or cost. The growth in size and weight could mean the poles or plinths need to be upgraded to hold the new transformer. This would incur even more costs. The driver for this action would then be an electricity cost that is higher than the cost of the changes required to reduce losses in the transformer.

Ideally, in this situation, a new technology, improving the material characteristics or improving the method materials, should be used so that cost, size and weight are contained.

A technology improvement in the form of amorphous core type transformers is not manufactured locally or to local specifications currently. Localising the amorphous technology has challenges. The amorphous technology uses thin ribbons of core, which are only supplied in two standard widths, to give extremely low no load losses. The thickness of the core makes it difficult to handle during manufacturing and the ageing properties of amorphous material is still questionable. An added difficulty in manufacturing is that in order to get the superior characteristics found on this type of core it needs to be processed by annealing the core in a magnetic field. The windings for the transformer are rectangular instead of round. Rectangular windings are not as strong, as circular windings, from a short circuit point of view.

Currently the sources of amorphous core materials are limited to two companies with a capacity that is a great deal smaller than traditional sources of core steel.

Given these challenges surrounding amorphous core and the fact that current technologies give similar results on the extreme capitalisation calculation, this technology does not currently make financial sense. This may change should the cost of energy continue to increase.

A working group has been reviewing the SANS 780 specification to reflect the needs of the industry as a whole.

The graph of the efficiencies of different international specifications (see Fig. 3) shows that the SANS 780 efficiency is lower than the specifications published in Canada, US, Japan and European specifications (Geldenhuys, 2009).

Considering the shortfall of our generation capacity, the ever increasing cost of electricity and the need to reduce the carbon produced by power plants, this situation needs to be improved. Given the information presented thus far it is evident that capitalisation formulas look after the specific need of the utility involved.

However there still needs to be a drive to reduce the maximum allowable losses in the South African industry without increasing the costs too much. From the values given in Fig. 1 it would seem that the simplest way to do this is to reduce the losses incrementally. This approach has the benefit that it will push the local suppliers and utilities towards reducing losses and raise awareness that there are total cost of ownership improvements that can be made without great changes in upfront costs. This will not bring South Africa in line with efficiency levels as set by other international specification bodies, but will also not see the purchase price of transformers increase by 50% or more of the current prices in one step, depending on the level of specification chosen.

Given the fact that the capitalisation formula allows for customers with greater need to reduce losses, this incremental approach to reducing maximum losses seems to be the best compromise at this time for the South African industry.

Conclusion

The South African electricity industry is under pressure to reduce costs, reduce emissions and increase output. Years of cheap electricity, an abundance of coal and an excess of generating capacity have led to an industry that is complacent and in dire need of measures to curtail these ills. The risk however is a knee jerk reaction to lack of action for a prolonged time, with respect to control of losses in distribution transformers. The case has been presented for an incremental decrease in maximum losses in the SANS 780 specification and the use of the capitalisation formula to ensure that utilities get optimised transformers that do not cost the industry dearly.

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Contact Gareth Stanford,
Powertech Transformers, Tel 021 534-268,
gareth.stanford@pttransformers.co.za

Case study: protection settings management at City Power

by H Boartman, DigSilent Buyisa, and H Nkuna, City Power

A case study on the implementation of an integrated protection settings management system (PSMS) at City Power.

This PSMS manages and stores all protective relays settings and parameters and allows for workflow management within the protection environment. The new system implemented at City Power allows for communication with manufacturer-specific settings software. It also keeps an historical trace and audit trail of all protection settings.

Modern numerical relays increasingly have more functions and thus, more protection settings. This, combined with ever expanding electrical networks, necessitates utilities to reconsider their approach to protection settings management [1, 2]. Historically, utilities have typically stored their protection settings in a combination of different systems with little to no security [1, 2]. This paper looks at how a utility, City Power, identified the need for a PSMS that provides a secure environment to store settings of complex numerical relays which can manage the workflow of protection settings [3].

Existing settings management

Background

Correct protection settings of relays are pivotal to the integrity of any power system. Power system engineers are tasked with ensuring the correct settings are applied to relays. These tasks include calculating settings, ensuring settings are applied correctly on the relay and ensuring an accurate record is kept of existing and past settings. Storage of past and present settings is pivotal to ensure quick replacement of a relay with correct settings in event of a relay failure [1]. Furthermore, present settings are required for testing of relays and to aid relay coordination studies in power system analysis tools [1, 2]. This requires utilities to store the power system protection settings in a centralised environment which can be access controlled.

The earliest forms of storage of protection settings was through a hard copy paper file system. This later evolved to storage on computer systems through means of spreadsheets or databases. Most of these systems had poor security and had a distinct lack of managing workflow sequence [1].

City Power case

City Power, like other utilities, has traditionally stored protections settings in a simplified format on different platforms. However, they consolidated all their settings on one central Excel spreadsheet. This spreadsheet kept a record of all the substations in the network and the settings for each bay relay. Basic parameters were captured, e.g. overcurrent plug setting and overcurrent time multiplier. This spreadsheet was stored on a central network drive which could be accessed by all protection users.

This system sufficed for as long as the majority of protection relays used in the system were electro-mechanical. The storage of settings in a spreadsheet become troublesome with advanced numerical relays and IEDs replacing the older electro-mechanical relays. Furthermore, security of settings was a concern since anyone could access the spreadsheet and change the settings as they saw fit. This undermined the integrity and validity of the settings in the spreadsheet.

If a setting was changed, there was no way to know who changed it, when they changed it and why they changed it. Users of the spreadsheet would typically download it to their computers, make changes but then fail to reconcile the data into the centralised spreadsheet. This eventually led to a situation where there were several versions of this spreadsheet, all with different settings.

The spreadsheet system also caused communication breakdown in terms of work flow sequence. Typically, the system engineers will issue settings to be applied to relays to the field teams who will do the application of settings. The spreadsheet system could not handle this workflow process of handing over settings and confirming that they were applied internally. This process was handled by engineers and field teams directly communicating with each other by means of email, phone or in person. This process was flawed as it required trust from both parties.

New system scope

City Power resolved to replace their existing haphazard settings management system with a new PSMS that is holistic and has the following features:

- Storage of protection settings of all fault clearing related devices (CTs, VTs, relays etc) on one central system.
- Settings lifecycle management to ensure the settings workflow sequence is maintained. The lifecycle should also indicate who did what, when and why. The PSMS must keep an audit trail of settings record changes and store historical data.
- Communication integration through an internal email system when changing the lifecycle state of settings. The PSMS should enforce compulsory emails to the next responsible person.
- The PSMS should be easy to navigate. It

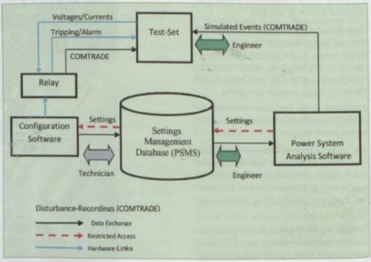

Fig. 1: Protection settings environment [4].

should be flexible in nature to allow for customisation to suit City Power's needs and way of working.

- Import and export of settings from the PSMS to and from the power system analysis tool, Digsilent Powerfactory, as well as import and export of relay configuration software files to and from the PSMS.
- Flexible user rights management to ensure security of the data stored on the PSMS.
- Full document management to ensure all data related to a settings record is stored centrally as well as easy report printing and data search.

This PSMS will form part of the protection settings environment as shown in Fig. 1.

The new PSMS at City Power

User interface

The new PSMS has an easy to use web-based interface. Minimal training is required for users at City Power to use the new PSMS. Navigation is made easier by defining a system hierarchy structure.

System structure

The PSMS stores settings of protection devices such as relays, CTs, VTs etc. These protection devices are physically located in bays in the network. In turn, these bays form part of substations which in turn could be part of a broader supply or geographic area [4]. The PSMS used at City Power is Digsilent Stationware. The system uses a location hierarchy structure. This hierarchy structure is used to find data quickly and easily.

A four layer structure was implemented at City Power. These layers are:

- Area (geographical)
- Substation
- Bay
- Device

The network was divided into geographical areas. Substations were stored per geographical area. All bays with its protection devices were stored according to substation. Bays were created per the equipment type they protect, for example: Feederbay (feeder), shuntbay (shunt capacitors), transformer bay (transformers) etc. Additionally, voltage levels were added to bays to ensure identification of the correct bay is easy. An example of this structure is shown in Fig. 2.

Fig. 2: City Power location structure [3].

Settings lifecycle

The settings workflow sequence is managed by the new PSMS. This is commonly referred to as a "lifecycle". The main aim of this lifecycle is to manage the process through which settings are initiated, planned, calculated, issued, applied and verified [1, 2, 3]. The lifecycle of the PSMS was customised to match City Power's internal processes and workflow sequence. City Power's internal work flow process for protection settings is shown in Fig. 3. Fig. 4 illustrates how this is implemented in the new PSMS.

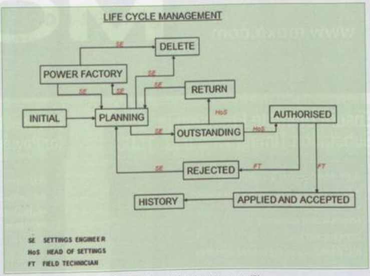

Fig. 3: City Power lifecycle management [3].

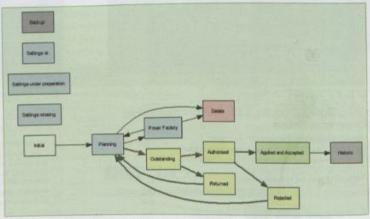

Fig. 4: City Power lifecycle in PSMS [3].

The lifecycle shows that responsibility rests with the settings engineer (SE) from inception until the settings record is placed in the "outstanding" state. The head of settings (HoS) then assumes responsibility to review the settings. After review, the HoS can change the settings record state to "authorised" or "returned". If the state was changed to "returned", then the settings will return to the responsible SE for revision or adjustment as required. Once "authorised", the setting will be issued to the field team (FT) which then assumes responsibility. The FT can return settings back to the SE for review or correction by changing the lifecycle state to "rejected".

The FT can change the lifecycle state to "applied and accepted" after settings were applied successfully and verified.

Audit trail

The PSMS keeps an audit trail of all actions on the PSMS, in particular when a settings record is moved from one lifecycle phase to another phase. The name of the user who changed the lifecycle phase and a time stamp of when it was changed are stored every time the lifecycle phase of a setting is changed. This ensures a full audit can be conducted on protection settings.

Email communication

The new PSMS has an email notification system built in to ensure when a lifecycle state is changed, the next responsible person is notified immediately through email. These email notifications were made compulsory where the status change of the settings record leads to responsibility handover. For example, an SE will not be able to change the state from "planning" to "outstanding" without sending an email to the HoS. This ensures there is no communication breakdown and the process remains streamlined. Furthermore, the system is hard coded to send a carbon copy email to City Power's protection department head. This was implemented to ensure transparency and to ensure that users accept responsibility when receiving notifications.

User management

Access to the PSMS is controlled through assigning users to user groups. User groups are assigned data access and functional rights according to their duties. The groups are divided into areas of responsibility. Through this it becomes easy to manage which users are allowed to affect changes to the PSMS or parts thereof and which users can only view the PSMS but not make any changes to the system. Each user has a unique username and password. The users' email address is also associated with their user account to assist with the email notification [3].

Five groups were created:

- *Administrators*: super users with super rights. Responsible for system administration.
- *Settings engineers*: can create locations, devices and settings. They can change the lifecycle state from "planning" to "power factory", "delete" and "outstanding".
- *Head of settings*: super user like administrator. Custodian of the system. Responsible for changing lifecycle state from "outstanding" to "returned" and "authorised".
- *Field technicians*: viewing rights for locations, devices and settings. Cannot change settings though. Users can change lifecycle state from "authorised" to "rejected" or "applied and accepted".
- *Viewers only*: viewing rights for locations, devices and settings. Cannot change settings or lifecycle state.

Fig. 5: Settings migration process.

Settings migration

City Power stored most of their existing network protection settings in a spreadsheet. These settings were migrated from the spreadsheet to the new PSMS system using an import converter [4].

The migration of the existing settings into the new PSMS had to be automated due to the large number of settings. The automation was conducted with a scripting program.

Migration converter

Automation through scripting in a programming language becomes easier when sample data is uniform. The existing spreadsheet with these settings was analysed and it was found that whilst the data was mostly uniform, it had some anomalies. To facilitate automation of migration the existing spreadsheet had to be revised into new uniform spreadsheets [3]. A small scripting "converter" application, written in the C# language, was written with the following outcomes:

- To create all the geographic areas, with the substations that belong to these areas. Additionally, create all the bays that belong to substations.
- To assign names according to the original spreadsheet to areas, substations and bays.
- To create devices in bays and migrate settings from spreadsheet to the devices.

The process for migration of settings is illustrated in Fig. 5.

Generic devices

"Generic" devices were created in the PSMS system due to the large amount of data that had to be migrated. The flexible PSMS allows the user to create devices with any parameters as needed on an XML format. The main settings spreadsheet captured parameters for relays and current transformers (CTs). Thus, the migration converter created two devices per bay, a relay and a CT. The parameters captured in these generic devices are shown in Table 1.

All of these settings were captured through automation with the migration converter.

Detailed numerical relays

The new PSMS installed at City Power can import and export detailed relay configuration files. The file formats supported for import and export are:

- Files formatted according to IEC 61850 [1, 4, 5].
- Manufacturer specific configuration settings files in ASCII or XML formats [4].

City Power obtained relay manufacturer specific configuration settings files of Schweitzer Engineering Laboratories (SEL) relays and Reyrolle relays in their network. These files were imported directly into the new PSMS using the built-in import function on the PSMS. This ensured all the settings from these relays were captured accurately as it was downloaded directly from the relays through the manufacturer relay configuration software.

The "generic" relays were deleted and replaced with the detailed relay import where possible. In future, over time, all the temporary "generic" relays should be replaced by the detailed relay models.

The calculation-relevant protection settings for the detailed relays (SEL and Reyrolle) can be imported and exported to the power system analysis tool, Digsilent Powerfactory [1, 4]. This allows for accurate simulation of power system protection system co-ordination and assists greatly with optimising relay settings [1, 4].

Device types	Parameter	Description
Relay	O/C ps	Overcurrent plug setting
	O/C tm	Overcurrent time multiplier
	E/F ps	Earth fault plug setting
	E/F tm	Earth fault time multiplier
CT	CT ratio	CT ratio
	CT class	CT class
	Ratio used	Ratio used
	Load setting in amps	Load setting in amps

Table 1: Parameters captured in generic relay device.

Document management

Additional documents

The PSMS has a document management system which allows users to upload any files relating to protection settings for a protection device [4]. This allows for centralisation of all the necessary documentation pertaining to a particular setting record. Examples of files that are stored are incident reports, test results, settings calculation sheets, technical manuals etc. These files can be in any format and are attached to the setting, relay or bay as an "additional document" which can be downloaded by users.

Reports

Reports can be generated from the new PSMS in PDF or HTML formats. These reports can be viewed with third party programs such as PDF readers.

Conclusion

City Power previously stored their protection settings on a centralised spreadsheet without being able to manage the settings environment. The spreadsheet system was replaced with a modern integrated protection settings management system.

This new PSMS has a user friendly web interface that requires minimal training to use. The system has an easy to follow internal structure which allows for quick data access.

Workflow sequence issues are now resolved through a central settings database with a settings record lifecycle. This lifecycle ensures there is no communication breakdown and provides an audit trail for all protection settings.

Data access for the PSMS is now controlled through user groups with specific access rights as per work duties set up by City Power.

Existing settings were moved from the spreadsheet platform into the new PSMS through an import converter. Temporary "generic" devices with settings according to the original spreadsheet were used to capture all the settings in the spreadsheet. The creation of protection devices with settings and locations like substations and bays was automated.

Detailed numerical relay or IED settings were captured where the downloaded relay configuration file was available. This replaced the temporary "generic" devices and the replacement of the temporary devices with detailed devices is an on-going process. The PSMS can import and export relay settings configuration files depending on the file format.

Detailed relay settings can be imported and exported to a power system analysis tool.

Automated reports can be generated from the new PSMS and all City Power documents relating to protection settings are managed through the system.

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Contact Hilton Boartman,
DigSilent,
Tel 011 512-0100,
hilton@digsilent.co.za

A network reliability informed approach to prioritising investment for sustainability

by Martin Cameron, Eon Consulting, and Dr. Clinton Carter-Brown, Eskom

Developing an understanding of the financial and economic implications of network infrastructure service levels requirements and the potential trade-offs between service levels, cost and the impact on the economy.

Electrical network infrastructure provision in South Africa has in general been based on a "least initial cost" approach for the last 15-plus years. The implications of this approach are not well understood in terms of the impact on customer service levels and the reliability of the electrical network supplying these customers. The "least-initial-cost" approach potentially has conflicting implications with current electricity regulatory requirements in terms of customer service levels and reliability. However, the trade-off between customer service levels and reliability relative to the cost of achieving expected performance levels is not well known in the South African context.

The aim of this paper is therefore to help develop an understanding of the financial and economic implications of network infrastructure service levels requirements and the potential trade-offs between expectations in terms of required service levels, the cost of achieving these and the potential cost to the economy (in terms of Cost of Un-served Energy[1]) of doing so – or not.

The paper is structured as follows: first context regarding societal cost and performance is provided, followed by the approach applied to develop a quantitative decision information framework to inform this topic. A practical demonstration of the approach is provided followed by the final section concluding with a summary of observations and recommendations.

Context: minimising societal cost versus performance expectations

Publically owned utilities typically attempt to design and operate electrical (generation, transmission and distribution) infrastructure to minimise the total cost to society [2]. This approach is generally referred to as value based planning. The concept is illustrated in Fig. 1 in a stylised fashion. This illustration deliberately places performance on the vertical axis and cost on the horizontal axis due to the focus on performance improvement (as opposed to traditional representations with cost on the vertical axis and performance on the horizontal axis).

The total cost curve consists of the sum of the utility's costs (to build, maintain, operate and improve the network) and the cost to the customer (of not having perfectly reliable electricity – typically monetised via the cost of un-served energy concept). The better (lower unavailability) performance a utility operates at implies that customers will be without electrical supply less frequently and for shorter periods. The result will be that the customer cost associated with the unavailability of electrical supply will reduce (indicated by the brown curve sloping towards zero as the performance measure on the vertical axis improves/reduces). However, to improve the expected network "design" performance, additional investment is typically required (as indicated by the downwards sloping green line).

The reliability of supply to end-users is dependent on the performance of the overall generation, transmission and distribution systems. Efforts to improve the performance of the distribution network are critical in ensuring reliable electricity supply to all customer end user segments [2].

The potential performance of a network, while influenced by operations, is mainly determined via the inherent design characteristics of the network e.g. lengths of feeders, number of customers supplied per feeder (which in turn is influenced by the development and land-use of an area e.g. urban, rural or agricultural etc.), inter-connectivity between feeders and redundancy of installed equipment. These structural issues are influenced by capital investment decisions made via network planning and design, and in turn have an impact on the inherent performance capability of a network (this will be discussed in more detail in this paper). For any given network with a set of possible maintenance interventions, there is a point beyond which additional expenditure via capital solutions will result in improved performance as compared to operational expenditure [1].

In this context, benchmark studies are often applied in decision making to inform expected levels of performance for utilities (and therefore performance targets). Eskom Distribution, for example, has conducted benchmark studies on a regular basis using references from the USA, Latin America as

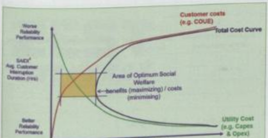


Fig. 1: Minimising societal cost.

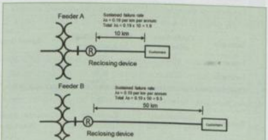


Fig. 2: Impact of topology on expected network performance.

Footnote

1) Cost of Un-served Energy (CoUE) is defined as the electricity supply's worth to a specific customer, a type or class of customer or the wider economy, usually measured in a monetary amount associated with the un-served energy experienced due to interruptions of electricity supply.

well as the European Union. Benchmarking outcomes should, however, be applied with circumspect, as there are some more detailed factors that must be considered when applying benchmark information for decision making, and this will be discussed further in this paper.

The connection of customers to the South African electricity grid is governed by the National Energy Regulator of South Africa (NERSA) via the South African Grid Code developed from June 2005 to August 2007 [4]. This code not only contains connection conditions but also investment criteria for such connections and is applicable not only to Eskom but also to other South African distributors such as municipalities.

According to the grid code a balance must be met between infrastructure cost options (both in terms of minimum cost of the energy supplied as well as the customer interruption cost) and the network's technical performance levels (RSA Grid Code, 2007, page 9).

Approach to develop a quantitative decision information framework

This paper builds on research work conducted by Eskom Distribution over the period 2008 to 2012 and elements described in [3, 5, 6, 7].

The basic approach that the authors are advocating is that by making use of modelled performance levels to inform decision making regarding network expected designed performance levels, one can provide a basis for better informed decision making (as opposed to historical or comparative international benchmarks, for instance).

Combining financial costs and potential CoUE implications and contrasting these costs with performance levels enables us to better inform the investment decision in a more holistic way. The broader socio-economic and political implications also need to be considered but are beyond the scope of this paper[2].

The value of this approach is therefore that it provides strategic context, and allows for a better understanding and appreciation of the respective trade-offs.

Our approach therefore contains the following elements:

- The ability to model expected design performance levels of the electricity distribution network in terms of customer focused measures.
- Incorporation of the utility costs (infrastructure) and customer costs (CoUE) associated with achieving such design performance levels.
- The ability to inform on expected specific performance levels – system average as opposed to specific networks (feeders) design performance.
- The dimension of economic sensibility and responsibility.
- The ability to illustrate the potential implications on a system (technical) level.

	Fundamental characteristics/parameters							
	A	B	C	D	E	F	G	H
A	Example	Line length (km)	Line failure rate (per 100 km p.a.)	Recloser count	Recloser failure rate (p.a.)	Transformer count	Transformer failure rate (p.a.)	No customers
	Feeder A	10	19,3	1	0,017	1	0,086	100
	Feeder B	50	19,3	1	0,017	1	0,086	100
	Operational characteristics/parameters							
	A	I	J	K	L	M	N	O
	Example	Customers affected	Expected outage frequency p.a.	Speed (km/hr)	Expected total travel time (minutes)	Isolation time (minutes)	Fault finding time (minutes)	Repair time (minutes)
	Feeder A	40%	2,0	120	10	5	30	60
B	Feeder B	40%	9,8	120	50	5	30	60
	Operational characteristics/parameters							
	A	P	Q	R	S	T		
	Example	Restoration time (minutes)	Customer interruptions (p.a.)	Customer interruptions hours (p.a.)	SADI (p.a.)	SAIFI (p.a.)		
	Feeder A	5	81,3	149,1	1,5	0,8		
	Feeder B	5	390,1	975,3	9,8	3,9		
	Operational characteristics/parameters – travel speed example							
	A	I	J	K	L	M	N	O
	Example	Customers affected	Expected outage frequency p.a.	Speed (km/hr)	Expected total travel time (minutes)	Isolation time (minutes)	Fault finding time (minutes)	Repair time (minutes)
	Feeder A	40%	2,0	120	10	5	30	60
C	Feeder B	40%	9,8	60	100	5	30	60
	Operational characteristics/parameters – travel speed example							
	A	P	Q	R	S	T		
	Example	Restoration time (minutes)	Customer interruptions (p.a.)	Customer interruptions hours (p.a.)	SADI (p.a.)	SAIFI (p.a.)		
	Feeder A	5	81,3	149,1	1,5	0,8		
	Feeder B	5	390,1	1300,4	13,0	3,9		

Table 1: Network topology – quantitative illustrative example.

Footnote

2) Refer to [3] for more detail on this dimension of this topic.

Fig. 3: Geographic representation of Eskom MV feeders for South Africa.

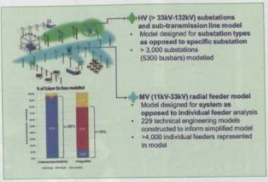


Fig. 4: HV and MV models context and coverage.

Determination of performance levels for an electricity distribution network

There are several network performance measurements applied by NERSA as well as by other regulators and utilities internationally. Our focus for this paper is mainly on SAIDI [3] (although our modelling also calculates SAIFI, CAIDI and RSLI).

In providing context we previously mentioned that benchmarking is typically used to inform utilities' executive management and the regulator of what the performance levels of a utility could be, and what it should strive for. Typically, statements are made that the utility aims to be in the top quartile of international performance as measured by SAIDI, for instance, irrespective of whether the fundamental network can actually achieve such a level of performance. The natural question that then comes to mind is "how can the utility achieve such levels of network performance – what would the utility need to do and what would it cost?"

The fundamental flaw with the benchmarking-based approach is its ignorance of current network topology (which in itself is a function of past policies and design philosophies), and its influence on the inherent performance level capability of the distribution system. We use a very simplistic example to illustrate the impact of network topology on the inherent performance level of a network illustrated in Fig. 2.

The only difference between feeder A and feeder B is the length of overhead conductor connecting the customers. We choose to use line length for this example as it typically adds the most significant exposure to failures on a system and is typically a function of settlement density. Feeder A has 10 km of overhead conductor, while feeder B has 50 km. The rest of the equipment, configuration and customers are assumed identical. The equipment on these feeders is installed and maintained in exactly the same manner, resulting in exactly the same failure rates. Operational responses to faults/outages are exactly the same. In terms of reliability, the only difference is the total sustained failure probability associated with the line.

We construct a simplified quantitative example of the two feeders and display the relevant characteristics (line length, recloser count, transformer count and customer counts) in Table 1. We assume all equipment failure rates to be identical between the two feeders. We assume 40% of customers will be interrupted in both cases. From an operational perspective we assume the same travelling speed, while also assuming the response team will travel the whole length of the feeder to fix an outage failure.

Evident is that the expected frequency of outages (column J, Table 1 B) will be higher for feeder B than A – solely as a result of the line length of the feeder. The reliability of feeder A (shorter) will therefore be better than that of feeder B (longer). The probability of failure on feeder B will be higher, while the travel time to fix a fault will also be higher. The resulting SAIDI for feeder B is therefore 554% higher than that of feeder A, but the operational response teams performed exactly the same (same dispatch times, travel speeds and repair times). All else remains constant (in terms of maintenance and operational response practice). The only way to improve feeder B network performance is to change the network topology – whether by adding additional fault finding and isolating devices, splitting the feeder to be shorter etc., all of which requires capital investment and changing the inherent designed performance capability of the feeder.

In a similar way, regulatory or policy differences can also have significant and sometimes unintended implications on network performance.

Take, for example, the implications of a policy change in maximum travel speed (column K, Table 1 C) as may be required to address safety requirements. In this example, we assume that the response team for feeder B is only allowed to travel at 60 km/h as opposed to 120 km/h. The difference in traveling speed (whether as a result of company policy, actual speed limits or conditions on the road) will cause the SAIDI for feeder B to increase from 9,8 to 13, resulting in a 33% deterioration in performance as measured by SAIDI.

It is therefore evident that customer densities (as they influence feeder length), network topology and the operating environment have a major impact on the expected level of network performance. These factors can vary significantly between utilities, and will be fundamentally different in urban and rural supply areas. Extrapolate this example to a full utility context and one can see why benchmarking purely based on the network performance outcome measure (e.g. SAIDI) does not necessarily reflect the actual performance level of the utility itself.

Furthermore, when comparing the network performance levels of different international utilities, we also need to consider aspects such as:

- None of the markets (typically benchmarked against) represented similar social responsibilities such as the Universal Access Plan [8] and its impact on South African electricity distributors.
- In addition, it is not clear which proportion of the international utilities making up the benchmark samples contain entities with similar typical mix of urban/rural environments. In this context, Eskom predominantly covers rural areas while municipalities cover the urban areas.

Footnote

3) For brevity purposes we do not define the indices in this paper. Refer to [2] p41-105 for more detail.

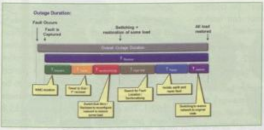


Fig. 5: Operational parameters included in models.

Customer sector	CoUE rate (R/kWh)
Industrial	6,69
Commercial	102,9
Agriculture	20,16
Residential	20,83
Mining	14,14
Traction	111,9
Municipal	29,53
Other	27,95

Table 2: CoUE rates assumed.

We therefore propose that if benchmarking between utilities is to be used to inform decision making and target setting, a better way of benchmarking (between utilities) would be to benchmark the different operational elements impacting on the outcome measure (SAIDI in this instance) as opposed to the outcome measure itself. It would therefore make more sense to benchmark on observed failure rates of major network equipment components and on operational aspects such as fault finding time and repair time, for instance.

The implication is that by simply comparing benchmark results (of technical performance and other parameters such as SAIDI and SAIFI) without more detailed context, misleading outcomes can be obtained and should therefore be applied with caution in decision-making.

However, we know that in practice this will be a challenge to implement (due to onerous information requirements). Fig. 3 provides some idea of the context and magnitude of the challenge when using the Eskom network as an example. There are more than 7000 MV feeders for which information must be collected and processed. For the full national South African context, this may well be in excess of double Eskom's MV infrastructure.

Our alternative proposal is to rather evaluate a utility's performance relative to its inherent expected designed performance levels subject to reasonable assumptions regarding operational performance and failure rate parameters.

The next section provides more detail in this regard.

Modeling design performance levels for an electricity distribution network

In order to inform expected designed modelled network performance levels we constructed an analytical simplified network reliability modelling framework capable of modelling both the relevant HV[4] and MV[5] network elements using summary network information.

For the MV model the following basic and generally readily available network component information is required for each MV feeder in the system:

- $Trfrs_{FDR}$ = No. MV/LV transformers on feeder
- LL_{FDR} = Total MV line length (km)
- $Fuses_{FDR}$ = No. MV fuses on feeder
- $Discs_{FDR}$ = No. MV isolators on feeder
- $Brkrs_{FDR}$ = No. MV reclosers & substation breaker
- $Cust_{affected}$ = No. customers interrupted
- $Cust_{total}$ = No. customers supplied on feeder

Failure rates for the following network components were applied:

FR_T = MV/LV transformer failure rate

FR_L = MV line failure rate

FR_F = MV fuse failure rate

FR_B = MV breaker failure rate

FR_D = MV isolator failure rate

For more details on the MV approach, refer to [7 , 6 and 5].

For HV (sub-transmission) a similar systematic approach was followed to derive the impact of the HV network performance on the MV feeders' network performance, and incorporated into the overall modelling process. More than 3000 Eskom substations (5300 individual busbars) are represented in the model accounting for 96% of both SAIDI hours and customer numbers as well as 78% of annual energy sold by Eskom Distribution (2011).

Different substation layouts have different reliability, e.g. double transformer substations are more reliable than single transformer substations. A substation supplied by two (or more) lines is more reliable than a substation supplied by one line.

Similar to the simplified MV approach described in [7], an HV approach[6] was developed that can be summarised in the following five steps:

- Identify and select most common substation configurations.
- Determine cost and reliability of all possible combinations and reduce to optimal reliability configurations.
- Determine cost rate (Δcost vs. reliability improvement) of the reduced configurations and select optimal reliability options.
- On a substation level – identify single preferred option based on optimising cost of energy not served (CoUE).
- Apply outcomes on system level model.

For the HV model the following sub-transmission network component information is required:

- HV busbar type classification (busbars, disconnectors, bus sections and bus couplers).
- HV transformers (source transformers only, i.e. transformers supplying the HV busbar).
- HV transfer busbars.
- HV line bays (source feeders).
- HV line bays (load feeders).
- HV line length (source feeders only).
- MV NEC/RT (neutral earthing compensator/resistor with an auxiliary power transformer).
- MV busbar type classification (busbars, disconnectors, bus sections and bus couplers).
- MV transfer busbars.
- MV busbars indoor/outdoor.
- MV transformers (source transformers only).
- MV line bays (source feeders).
- MV line bays (load feeders).
- MV line length (source feeders only).

Footnotes

4) High voltage, nominal voltage levels > 33 kV ≤ 132 kV – also referred to as sub-transmission.

5) Medium voltage, nominal voltage levels > 1 kV ≤ 33 kV.

6) A more detailed explanation on the HV methodology will be published in the future.

- Number of HV customers + energy served.
- Number of MV customers + energy served.

Both the HV and MV models consider operational parameters such as dispatch time, travel time, time to sectionalise, fault finding, repair time and final restoration times as illustrated in Fig. 5.

The models can also accommodate various interventions and their associated capital costs. Typical infrastructure options that a predictive reliability model can simulate include (model capabilities indicated in brackets) [9]:

- Line reclosers (yes)
- Sectionalising switches (yes)
- New feeder tie points (no)
- Feeder automation (yes)
- Undergrounding circuits (yes)
- Replacement of ageing equipment (yes)
- Load transfers between feeders (yes)
- New substation and substation expansions (yes)
- New feeders and feeder expansions/splits (yes)

The customer cost component is incorporated through the concept of CoUE. There are various methodologies for estimating and interpretations of the CoUE concept – all of which have various advantages and drawbacks. Surveys used to inform CoUE almost always overstate customer cost of poor reliability compared to the customer willingness to pay approach (in addition customer gaming behaviour can lead to intentionally overstated responses) [2].

For illustrative purposes we make use of the CoUE rates as listed in Table 2. It is not the focus of this paper to discuss these in detail.

We now have an approach based on an analytical modelling framework that allows for HV and MV system level analysis (using basic data) of different infrastructure (Capex) and operational strategies[7] for which the infrastructure cost and performance implications can be analysed in the context of utility cost, energy not served, CoUE and relevant network performance indices e.g. SAIDI.

Practical application of the framework – some examples

In order to illustrate the application of this framework we provide an overview of an analysis performed for a section of the Eskom network.

The specific network area in question supplies more than 840 000 customers (19% of total Eskom), has more than 377 MV feeders associated with this customer base amounting to around 36 000 km of MV line (average MV feeder length of 96 km) and more than 46 000 MV/LV transformers.

Our modelling outcomes are based on national parameter value assumptions (e.g. equipment failure rates, travel speeds etc.), but adjusted to account for the specific assets and environment (e.g. distances, lightning density, vegetation etc.) in the specific network area.

Before the models and approach are used to assess the implications of interventions, the modelled results (expected/designed performance) for the present network are compared with the actual performance results as illustrated in Fig. 6. The trend comparison demonstrates that our assumptions applied in the model may be on the conservative side, as the actual SAIDI for the period January 2009 to August 2012 appear to be generally lower than the modelled estimate of 62,1. The average over the period is 55,8 hours. per year and trending down towards 50 hours per year.

This comparison with actual reported information provides us with confidence that the methodology and input parameters suitably (and conservatively) models the reality for this network.

To further illustrate the application of the model we construct three scenarios and investigate the impact on the sample network SAIDI as follows:

- First we investigate the reliability implications of operational improvements (A); then
- We investigate infrastructure (Capex) interventions applied with the sole objective of reducing SAIDI (B1); and lastly
- Infrastructure interventions conforming to RSA Network Code requirements (B2 – optimising the net sum of the utility and customer costs).

Scenario A – SAIDI reduction via operational improvements

In terms of the operational improvement scenario[8], we construct a "what-if" analysis where:

- We reduce the failure rates for major components such as MV lines and MV/LV transformers by 10% (in practice this could be achieved through e.g. better execution of maintenance) and

Equipment	Unit	Base value
MV		
Number of feeders (base system)	No	377
MV line (Base system)	Km	36 120
MV transformer count	No	46 209
Recloser count	No	978
Fuse count	No	43 751
MV customers supplied (NEPS)	No	841 442
HV		
Substations	No	623
HV busbars	No	167
MV busbars	No	291
HV-HV transformers	No	20
HV-MV transformers	No	287
MV-MV transformers	No	151
HV lines	Km	2391
HV customers supplied (NEPS)	No	4
Total customers supplied (NEPS)	No	841 446

Table 3: Sample area base equipment volumes.

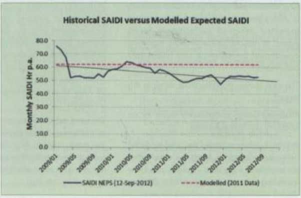
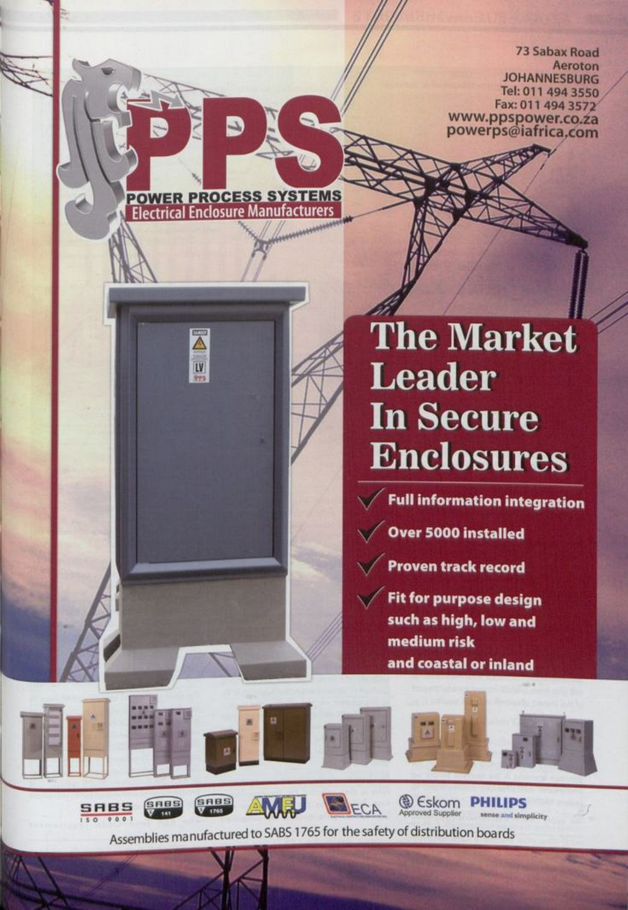


Fig. 6: Eskom sample area SAIDI actual vs. modelled expected baseline.

Footnotes

7) For the current version of the model the associated OPEX or operational costs related to capital interventions are not catered for at the time of writing this paper.

8) For purposes of this illustrative scenario we keep the HV system parameters unchanged.



73 Sabax Road
Aeroton
JOHANNESBURG
Tel: 011 494 3550
Fax: 011 494 3572
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powerps@iafrica.com
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SABS ISO 9001
Eskom Approved Supplier
PHILIPS sense and simplicity
ECA
AMEU
Assemblies manufactured to SABS 1765 for the safety of distribution boards

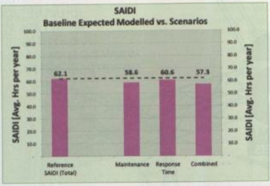

Fig. 7: Eskom sample area SAIDI actual vs. modelled and operational improvement scenarios.

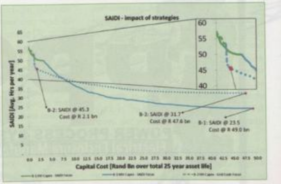

Fig. 8: Sample area SAIDI infrastructure improvement scenarios.

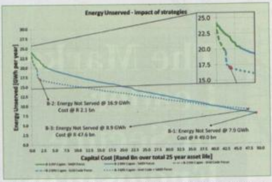

Fig. 9: Sample area energy un-served infrastructure improvement scenarios.

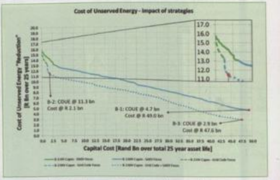

Fig. 10: Sample area cost of un-served energy infrastructure improvement scenarios.

- We reduce the despatch time and repair times (for lines and transformers) by 10%.

The outcomes[9] of these actions are also illustrated in Fig. 7. It is evident that the improvement in equipment failure rates results in a 5,7% reduction in SAIDI (from 62,1 to 58,6) while the improvement in despatch and repair times results in a 2,3% reduction in SAIDI (from 62,1 to 60,6). When combined, the overall impact is a 7,8% reduction in SAIDI (62,1 to 57,3).

The reader must keep in mind that "normal" network upgrades (required to address thermal, voltage and fault level requirements) will also have a SAIDI impact and forms part of the impact observed in these results.

Scenario B – SAIDI reduction via capital interventions

For these scenarios we assume that the operational improvements described in the previous scenario A are realised before we implement infrastructure interventions to reduce SAIDI further.

We apply capital interventions (additional fusing, reclosing, line splits and new substations) in order to achieve a lower SAIDI outcome, and observe the cost implications.

In the first instance, we apply a pure SAIDI reduction focused approach (scenario B-1) where the interventions are applied on feeders with the sole aim of reducing SAIDI – irrespective of the cost implications. The outcomes of this approach are represented by the solid green (HV) and blue (MV) lines in Figs. 7, 8 and 9 for SAIDI, energy un-served and CoUE respectively.

The dashed green (HV) and blue (MV) lines represent a scenario where we apply a test to each set of interventions from the RSA Grid Code requirement perspective (scenario B-2). In this context we test whether the benefit (annual CoUE reduction) to cost (annualised capital cost) is greater than 1. If this is the case, we apply the interventions and incur the cost and obtain the SAIDI improvement, otherwise not.

The feeder with the highest benefit to cost ratio is then selected for implementation first, followed by the next highest etc. Due to the data quality, the simplified approach and average assumptions that may cause our model to be less accurate, we take a conservative stance and reduce this threshold value from 1 to 0,8 to cater for these technical issues.

Lastly, we apply the SAIDI focused approach after all the grid code requirements (balance between cost and benefits, scenario B-3) have been applied to the same set of feeders, until the minimum SAIDI is achieved (represented by the dotted curves). The outcomes for SAIDI, energy un-served and CoUE are discussed next.

SAIDI results

The solid green (HV) and blue (MV) lines in Fig. 8 represent the impact each individual feeder has on SAIDI (vertical axis) and the related capital rand billion cost requirements (horizontal axis). Evident is that the pure SAIDI approach (B-1) reduces the SAIDI from 57,3 (SAIDI after operational improvements) down to 23,5 (33,8 hours or 59,0% reduction) at a capital cost of R49-billion (or R1,45-billion per SAIDI hour improved).

The RSA Grid Code requirement

Footnote

9) Due to the fact that currently the modelling does not include costs for these operational improvements we only show the SAIDI outcomes for these scenarios.

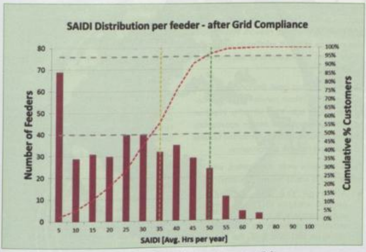

Fig. 11: SAIDI spread – grid code requirement met (B-2).

Equipment	Unit	Scenario B1 SAIDI focus value	Scenario B2 Grid code focus value	Scenario B3 Grid code followed by SAIDI value
HV System				
MV Busbars (existing substations)	No.	174	73	176
as % of base	%	60,2%	25,3%	60,9%
HV Busbars (existing substations)	No.	83	51	89
as % of base	%	50,6%	31,1%	54,3%
HV-HV transformers (existing substations)	No.	-	-	-
as % of base	%	0,0%	0,0%	0,0%
HV-MV transformers (existing substations)	No.	42	19	42
as % of base	%	17,4%	7,9%	17,4%
MV-MV transformers (existing substations)	No.	28	3	28
as % of base	%	23,5%	2,5%	23,5%
New substations required	No.	331	20	445
as % of base	%	201,8%	11,9%	271,2%
MV System				
Fuses (additional)	No.	565	2260	2825
as % of base	%	1,3%	5,2%	6,5%
Reclosers (additional)	No.	137	410	547
as % of Base	%	14,0%	41,9%	55,9%
Reclosers (system)	No.	1115	1388	2503
as % of base	%	114,0%	141,9%	255,9%
Number of feeders to split	No.	265	63	328
as % of base	%	70,3%	16,7%	87,0%
Number of additional feeders to build	No.	1324	78	1779
as % of base	%	351,2%	20,7%	471,9%
MV overhead line required	km	28 748	6528	35 276
as % of base	%	79,6%	18,1%	97,7%

Table 4: Equipment volume implications.

scenario (B-2) achieves a reduction in SAIDI from 57,3 down to 45,3 (twelve hours or 20,9% improvement) for a capital cost of R2,1-billion only, yielding R0,17-billion per SAIDI hour improved.

When we apply the SAIDI focus drive after the RSA Grid Code requirements are met (B-3), the outcome is that SAIDI reduces by 44,6% at R1,86-billion per hour.

Therefore, for 30 – 40% of the relative gain obtained (20,9% [B-2] versus 59,0% [B-1] and 44,6% [B3]), the RSA Grid Code requirement scenario provides the best yield (between eight and ten times better) in terms of rand/SAIDI hour improvement at R0,17-billion (as opposed to R1,45-billion and R1,85-billion).

Energy un-served results

Evident from Fig. 9 is that for scenario B-1 the energy un-served reduces from 24,2 GWh down to 7,9 GWh (67,4% reduction) at a cost of R49-billion (or R3,01-billion per GWh energy un-served avoided).

The RSA Grid Code requirement (scenario B-2) yields R0,28-billion per GWh avoided energy un-served) with a 30,2% improvement in GWh energy un-served avoided, while scenario B-3 results in R3,11-billion per GWh for a 63,4% improvement.

CoUE results

The cost of un-served energy impact is illustrated in Fig. 10. For scenario B-1, the 25 year expected CoUE total reduces from R15,8-billion to R4,7-billion (70,1% reduction).

In the case of scenario B-2 the CoUE reduces by 28,4% (down to R11,3-billion) while in the case of scenario B-3 the CoUE reduction is 81,3% (down to R2,9-billion). Since the energy un-served only reduced by 63,4% for this scenario, it can be inferred that the relatively larger reduction in CoUE is related to higher CoUE rate customers (e.g. commercial, traction, mining and agriculture).

Although the benefit/cost ratio is evaluated per feeder, the outcome for this measure on a system level reflects that the RSA Grid Code requirement (scenario B-2) has a positive (greater than 0,8 as explained previously) benefit/cost ratio of 2,17, versus scenario B-1 at 0,23 and scenario B-3 at 0,27.

SAIDI spread

Fig. 10 shows the resultant spread in SAIDI results associated with the RSA Grid Code compliant investment level for scenario B-2.

Although the infrastructure interventions illustrated by scenario B-2 results in an overall reduction of expected SAIDI from 57,3 down to 45,3, the spread of feeders in terms of their expected SAIDI's remains quite wide (from 2,7 hours. p.a. to 66,5 hours. p.a.). The 5% worst served customers can still expect to be on a feeder with a SAIDI in excess of 50 hours p.a., while 56,8% of customers will be on a feeder with an expected SAIDI of less than 35 hours p.a.

Analysis of results

The following observations can be made:

- Scenario B-1 results in the largest SAIDI reduction, but the associated investment cannot be justified from an economic perspective (the reduction is CoUE is less than the associated expenditure). Other drivers will need to motivate such an investment strategy.
- Scenario B-2 results in a relatively large reduction in CoUE for comparatively little capital cost. These investments are in accordance with the RSA Grid Code requirements, and are justified from an economic perspective (minimise utility and customer cost). This scenario results in investment on networks supplying customers with high sales volumes and high economic impact e.g. municipal supplies and industrial and commercial customers. As a result, while the CoUE reduction of 28,4% is appreciable, the SAIDI reduction of 20,9% is comparatively small as the number of customers impacted by these investments is comparatively small.
- Once at the economic optimum grid code compliant point (B-2) a further SAIDI focused investment is not justified from an economic perspective (economic benefit is lower than the cost). However socio-political drivers may result in further investment to reduce SAIDI. The cost implications of such a SAIDI reduction are massive (> R47-billion for a further 13,6 hour reduction in SAIDI). The basis for such investment is not clear and needs to be carefully considered. Such a SAIDI focused investment drive results in expenditure on networks supplying high numbers of customers, and specifically MV feeders supplying rural electrification.
- The results presented only illustrate the associated capital cost. The additional infrastructure will also incur additional operational costs, which have not been included in this example.

The new equipment volume implications are listed in Table 4.

Evident is that the RSA Grid Code requirement (B-2) only allows for 63 MV feeders to be split in this network, while the SAIDI focused approach (B-1) will split 265 feeders. Similarly the RSA Grid Code requirement (B-2) will only imply 20 new substations to be built, while the SAIDI focused approach (B-1) requires 331.

Summary and conclusion

The approach outlined in this paper supports the assessment of different reliability centred investment strategies as applied to sub-transmission and distribution networks. Outcomes are measured in terms of capital cost, energy not supplied, cost of un-served energy and reliability measurement indices such as SAIDI. The approach is pragmatic using readily available network information, and a range of inputs relating to equipment failure rates, and operational response and repair times.

The approach has been demonstrated on a section of the Eskom network for a number of investment scenarios with the intention to inform strategies to ensure appropriate investment that balances the costs and benefits of improving network performance.

Three scenarios were investigated, and the salient points are as follows in summary:

- Although the RSA Grid Code aligned scenario (B-2) only obtained approximately a third of the SAIDI reduction relative to the SAIDI focused scenarios (B-1 and B-3), the RSA Grid Code aligned scenario exhibited the best return for investment for SAIDI (rand/SAIDI per hour reduction), energy un-served (rand/GWh un-served avoided) as well as CoUE (CoUE reduction to capital cost ratio) by orders of magnitude.
- Translated into equipment volume implications, the RSA Grid Code aligned scenario also results in significantly less new equipment, feeder splits and substations required. This optimised or balanced return (between financial cost and economic benefit) is what the RSA Grid Code in essence seeks to achieve, and South African electricity distributors should strive to apply it as such in practice.
- We have also illustrated that although a strategy aligned with the RSA Grid Code will yield a significant improvement in performance indicators, the individual feeders (and therefore associated customers) will still experience a wide range of expected performance levels, while most of the energy un-served avoided (saved) will be associated with larger energy consuming customers as opposed to residential households.
- Strategies to improve SAIDI beyond that of the economic optimum (scenario B-2) need careful consideration, and the justification thereof may need to consider other socio-political requirements not reflected in CoUE optimisation approaches.

The approach can inform various questions typically posed by strategic and tactical engineering management decision makers, and in this context we have demonstrated the practical application of our proposed approach to a real-world section of the Eskom network.

Our example illustrated how alternative scenarios and strategies can have very different outcomes and implications (costs and benefits as well as equipment/logistics requirements). It is evident that a coordinated and integrated approach is required to balance operational improvements, capital expenditure, optimise CoUE and consider the political and social implications of SAIDI, especially for worst served customers.

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Contact Dr. Clinton Carter-Brown,
Eskom Technology Group,
Tel 011 655-2472, cartercg@eskom.co.za


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Power quality monitoring system (PQMS) for the City of Ekurhuleni

by Stephen Delport, City of Ekurhuleni

Quality of supply (QoS) in electrical energy is important for the sustainability of a local utility. The annual budget has to be based on a realistic assumption that retailing electrical energy will realise a projected profit. Sewerage, water and others are services rendered by local utilities operating within budgets subsidised from the profit made by selling electrical energy. But selling electrical energy is in itself not sustainable if the quality does not empower the user to generate profit.

Ekurhuleni has implemented a web-based power quality management system (PQMS). Power quality management has proven to be an important aspect of managing risk in the electrical supply industry (ESI) within Ekurhuleni. An understanding of the quality of the power from Eskom to the point of delivery to the end-user, is needed to formulate maintenance, repair and other intervention measures ensuring minimum standards in QoS.

Instrumentation has been placed at points in the network to ensure comprehensive visibility on voltage parameters. If QoS is above minimum standards, some validity exists in the assumption that the quality by which the energy used is not of concern.

A single voltage waveform incident can result in numerous voltage waveform events all over the network. Each voltage waveform event, if the duration and depth are sufficient, can cause a local interruption in production to the end-user. Although an interruption in the voltage supply was not recorded, the effect to the end-user is similar. Voltage waveform incidents are thus a "global" network problem which can require more comprehensive intervention measures than, for example, solving reliability issues at only a local feeder to a single client.

The widespread integration of QoS instrumentation in the Ekurhuleni network and on-line access to information enabled voltage waveform incidents (e.g. dips) to be analysed in the context of the root cause and source of the incident. It is therefore possible to assign ownership (internal/external) to each voltage incident and to extract the root cause from operational information such as copper theft, vegetation, lightning etc. Minimum specialist knowledge to use the system is needed as the web-based SQL interrogation of the PQ database provides the user with practical information, in proper context, rather than a tsunami of PQ data recorded at many instruments due to single incident. Data analysis is mostly automated and operational personnel can focus on using the information on a day-to-day basis.

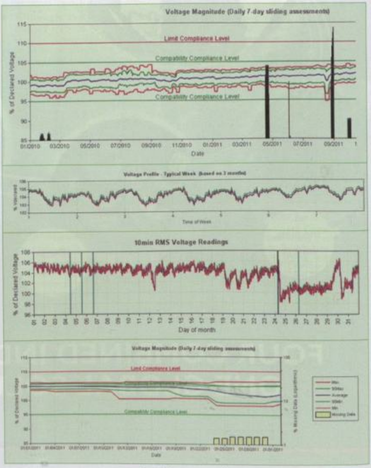

Fig. 1: Assessment trends.

Analysis of PQ data collected in this database for a number of years has resulted in Ekurhuleni being able to benchmark network performance. Characteristic levels in steady state parameters could be established and trends identified by understanding how, for example, voltage total harmonic distortion (VTHD) changes with time within a specific network. Indicative numbers in voltage sags could be calculated as functions of network type (cable/overhead) and voltage level.

The intention is to use characteristic numbers in voltage sags to benchmark any singular site against what the rest of the network experiences.

The benchmarking results are useful in supporting potential investors by means of information on the network distortion levels which they can use to specify equipment immunity levels to obtain a realistic compatibility level between supply and use conditions.

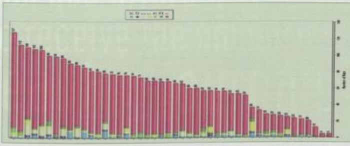

Fig. 2: The amount and type of voltage dips experienced in one specific town with EMM.

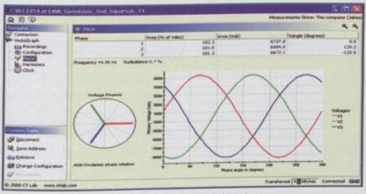

Fig. 3: Commissioning snapshot of voltage phasors.

Daily reports pinpointing power quality exceedences and reporting on network incidents.	
	Power quality assessments according to NRS048-2:2007. Also available is a viewer for the raw 10-minute trended data, as well as data availablity.
	Yearly power quality reports, including tables 9 to 12 as documented in the NERSA reporting standard.
	Incidents are formed by grouping classified events (dips, surges etc) that occurred within a specific time window from each other. Probabalistically they share the same cause. Incidents can be viewed and information about the cause can be annotated. Drill-down to individual events is possible.
	Reports on events for individual sites. Both short events (dips and swells) as well as interruptions are reported on.
	Reports to show performance of a collection of sites and ranking of individual sites.

Fig. 4: PQ reports available on log on.

With the increased globalisation of industry, including free trading of electrical equipment, it will be increasingly necessary for power quality to be monitored and regulated. From the best practices, it will provide a common framework for quality of supply and a step in the right direction towards globally acceptable standards and limits.

In a visionary step, the head of Department: Energy, Mark Wilson, recommended to the mayoral committee of the City of Ekurhuleni to commit to a power quality monitoring program, as far back as September 2003. A resolution was taken that a power quality management system and programme must be implemented for its entire network, as well as those identified by experience as requiring special attention e.g. key customers above 1 MVA.

The Ekurhuleni distribution networks are supplied with electricity from 45 Eskom intake points, at voltage levels ranging between 132/88/66/44/33/22/11/6,6 kV. From here a mixed base of approximately 350 000 customers are supplied with electricity connections. The sum of all the maximum demands at the various Eskom intake points during the winter months exceed 2400 MVA. Approximately 99,5% of the City of Ekurhuleni's electricity is purchased from Eskom and 0,5% from a neighbouring metro municipality, namely City Power, Johannesburg.

The City of Ekurhuleni has made strong progress to implement a proper power quality management system that complies with the NERSA directive and reporting requirements.

The city has developed a power quality charter which defines its commitment to ensuring the delivery of electricity of appropriate quality and of dealing with problems that customers may experience with regard to quality from time to time. This charter has been approved by the South African National Energy Regulator as meeting the requirements of its power quality directive.

The Ekurhuleni Metropolitan Municipality tries to minimise potential quality of supply problems arising in its networks, but it should be noted that the type of network e.g. overhead lines or underground cables, that supply customers will have a significant impact on the quality of the supply.

The steady state voltage is the voltage a customer can expect to receive under normal operating conditions. Since the loads on a utility are constantly changing, it is impossible to maintain a complete constant voltage.

South Africa's NRS-048 addresses compliance limits set at 95% of measurement intervals and allows utilities and customers to source appropriate equipment for the quality of power they will be exposed to.

Note: From above the standard statistical model allow 8,4 hours per week (or 52 x 8,4 per year) of unregulated power quality, and utilities compliance (or non-compliance) is assessed regardless of the severity of the event!

Voltage regulation magnitude indicates a slow but definite upward trend when analysing annual data. If one would have only looked at the monthly data, the added value may have been missed.

Generally, the Ekurhuleni networks meet the standardised limits of maximum and minimum voltage limits. Many customers actually experience voltage variations better than the plus and minus 5% compatibility levels and seldomly report on exceedance of the plus or minus 10% maximum and minimum

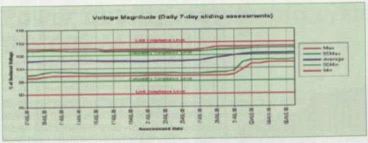

Fig. 5: Voltage magnitude compliance with NRS084-2.

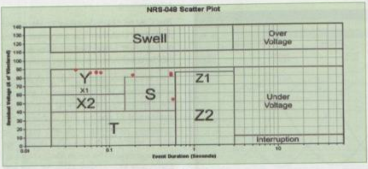

Fig. 6: NRS-048 scatter plot.

Start date	Duration	Residual voltage	Affected channels	NRS048 category
7 June 2009 15:38:38	0,57 s	53,38%	1,2,3	Dip class S
9 June 2009 10:13:22	0,54 s	83,38%	2,3	Dip class Y
12 June 2009 10:14:11	0,08 s	85,43%	1,3	Dip class Y
13 June 2009 12:13:20	0,54 s	81,21%	2,3	Dip class Y
23 June 2009 12:05:58	0,06 s	85,63%	1,3	Dip class Y
23 June 2009 12:28:05	0,07 s	86,21%	1,3	Dip class Y
23 June 2009 12:28:05	0,19 s	81,92%	3	Dip class Y
25 June 2009 14:22:02	0,07 s	85,63%	1,3	Dip class Y
25 June 2009 14:22:05	0,04 s	89,33%	3	Dip class Y

Table 1: Voltage dip/swell assessment.

limit values required to be maintained on the network.

The question of what level of services is acceptable certainly complicates the costs of providing a certain level of service with many factors including climate, geography, system design and load density. These differences even exist within Ekurhuleni's service area – it has even been noticed that there are significant differences in the service level of quality from one customer to another within Ekurhuleni.

The concept of minimum service quality levels is a very controversial topic among electricity service providers. The economic law of diminishing returns certainly applies to increasing the quality of electricity as it applies to most quality assurance programs. Electrical engineers in utilities note that any level of service quality can be achieved, but the costs of achieving certain levels cannot be economically justified. This fact must, however, be balanced with increasing quality of service required by consumers.

The specification of the PQMS and selection of sites to be monitored in the Ekurhuleni distribution network were planned to address all of the abovementioned issues.

The following is a brief summary of the tender document specifications:

Scope of the City of Ekurhuleni power quality contract

An Oracle based on-line power quality (PQ) monitoring system was developed according to Ekurhuleni's requirements. This system is capable of serving data collected from a network of remotely installed VectoGraph and ProvoGraph instruments to both Ekurhuleni personnel and to key customers via the Internet. The network of remotely installed instruments is permanently connected via a GPRS communications link to the internet-based PQ database.

More than 400 metering points are currently operational.

Daily system operation

Information is captured daily, audited for completeness, and then e-mailed daily by means of a PQ assessment report of the previous day to the control room operators. Ekurhuleni personnel (control room operators) classify each incident direction, external or internal (transmission or distribution), while the area engineers have to classify the root cause of each incident. Ekurhuleni personnel generate all monthly and ad-hoc reports.

The successful contractor has to see that the entire system is on-line and up-to-date for 95% of the time. In the event of an unforeseen system failure, it is expected from the contractor to have the system restored within five working days.

Annual report

The EMM PQMS is capable of compiling annual PQ reports. This type of reporting is a science in its infant stage. The report is mainly used as a management report, but parts of it will be published to EMM's customers and will comply with NERSA power quality directive requirements and with NRS048.

Product training, power quality training, and power quality mentoring

Ekurhuleni receives product training on an annual basis to accommodate new personnel and to remain updated on the latest functionality and features.

The training includes the following (as a minimum):

- Discussion of power quality instruments and the abilities of each instrument type.
- Installation, commission, configuration and management of power quality instruments and communication equipment.
- Introduction to all measured parameters.
- Product usage.
- Software Installation.

The PQ training includes the following (as a minimum):

- Fundamental principles of power quality.
- Up-to-date overview on the NRS 048 and NERSA's power quality directive.
- Overview on power quality management principles.

Ekurhuleni also provided for a power quality mentoring programme as part of its bid

EngineerIT
2012 august
Extend Industrial Reliab
to Control Rooms
FEATURING
Computing & software
energize
Efficient Smart grid s
PositionIT
March 2012
GeoSystems Africa
The Number One
Leica distributor
in Southern Africa
Vector
April 2012
you need to succe

Class Code	Duration	Depth	Serial	Node	Event Date
Dip Class S	0.57	53.378271 %	Vec000002076	EMM_Brakpan_Dalpark_T3_11kV	07-Jun-2009 15:38:38.750

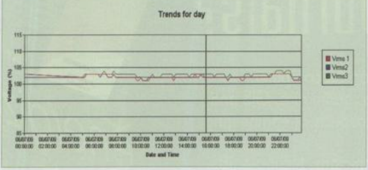

Fig. 7: The event report.

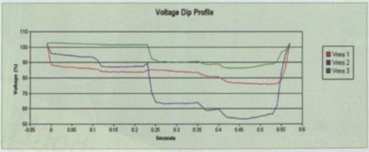

Fig. 8: The voltage dip profile.

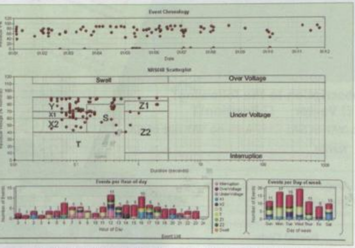

Fig. 9: A voltage dip is a sudden reduction in RMS voltage supply as defined in NRS048-2:2007 section 3.1.20 and IEC61000-4-30:2003 section 5.4.

requirements to appoint a contractor. This is to fast-track the learning curve and to ensure sustainable growth and knowledge transfer.

Investigation assistance

The contractor is required to provide for power quality investigation process and procedure in-line with Ekurhuleni's PQ management system. The power quality investigation process makes provision to address customer complaints received from Ekurhuleni's connected customer base.

After power quality instrument installation a commissioning snapshot of voltage phasors is stored for future reference and proves acceptance of installation (see Fig. 3).

Voltage magnitude assessment (voltage regulation)

Fig. 5 depicts voltage magnitude compliance with NRS 048-2, and it is expressed as a percentage of the declared RMS voltage. Daily, seven-day sliding assessment values are compared to specific compatibility and limit criteria. Upon evaluating this voltage-RMS level it is immediately clear that the voltage level has risen above the upper compatibility level of 105% and requires attention.

Voltage dip/swell assessment

Categorised voltage dips (a sudden reduction in RMS voltage supply as defined in NRS048-1:1996 section 3.1.20 and IEC61000-4-30:2003 section 5.4.) Customised report periods can be selected (see Table 1) e.g. daily, monthly, quarterly, yearly etc. (see Fig. 6).

By selecting (clicking on) any dip event a detailed drill-down of the event is obtained (see Fig. 7).

Supply reliability assessment in terms of interruptions

Supply reliability is assessed according to NRS048-2:2003 section 4.3 in terms of interruptions. These interruptions are classified as either momentary (short) or sustained (long) (see Tables 2 and 3).

Incidents are formed by grouping classified events (dips, surges etc.) that occurred within a specific time window from each other. They share the same cause in all probability.

Reports include:

- *Show most recent incident:* this will bring up the most recent incident that occurred on the network.
- *Incident browser:* used to investigate incidents over a selected period of time. A list of incidents is given for the period selected. Each incident can then be viewed and the related classified events can be drilled down to each incident (see Fig. 10).

With the implementation of a PQMS, Ekurhuleni is already in a better position to establish network-wide performance criteria as a means of informing end-users regarding the level of service that they can expect, or as a means of proactively identifying and investigating potential problem circuits.

Voltage regulation systems and power quality analysis

The latest series of voltage regulators found on the market today for control

Category	Number of events	Total duration
Momentary	2	2:36.91
Sustained	1	4:34:10.7

Table 2: Interruptions can be momentary or sustained.

Start date	Duration	Category
2009/06/05 10:56:33	1:12.75	Momentary
2009/06/05 11:03:17	1:24.16	Momentary
2009/06/07 12:11:45	4:34:10.7	Sustained

Table 3: List of interruptions.

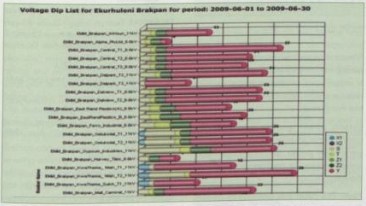

Fig. 10: Voltage dip list for Ekurhuleni Brakpan for period: 2009-06-01 to 2009-06-30.

of transformer tap changers are far better than those which go back to the post world war era. State-of-the art voltage regulating systems today offer ease of use and simple operation, from manufacturers that have proven track records. However, measuring and monitoring the voltage levels due to possible manual overriding of the control systems, e.g temporarily placing an automatic tap changer on a fixed tap position, may affect the voltage levels. By monitoring this on a daily basis, this will be picked-up very soon, especially where the loading on the transformer varies considerably (see Fig. 11).

When the voltage regulating control system is combined with permanent and continuous power quality monitoring instruments, the overall number of tap changes may be reduced. This will also have a positive impact on the maintenance budget (it is already possible to monitor and record which taps have been used the most and then service those only).

Conclusion

Although the City of Ekurhuleni has made much progress in establishing a power quality monitoring system, it has certainly not reached the fully matured state envisaged for the future.

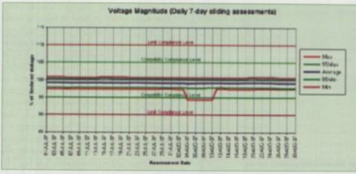

Fig. 11: Voltage magnitude (daily seven-day sliding assessments).

The implementation and results obtained by the power quality monitoring program at the City of Ekurhuleni have identified the essential need for assessing and monitoring power quality .

At the onset of the PQMS project, Ekurhuleni agreed to lead into unchartered territories for the benefit of the industry.

The implementation of Ekurhuleni's PQMS can be seen as a milestone reached in the submission of power quality reports to NERSA.

The cost impact of managing a power quality instrument per primary transformer is insignificant compared to the monthly revenue stream generated by the output of that transformer.

System power quality benchmarking applications involve the installation of permanent power quality measurement instrumentation at predetermined sites on the system.

Note: This paper was prepared by Stephen Delport and the views contained in it do not necessarily represent the views of Ekurhuleni Metropolitan Municipality or of the AMEU(SA).

Acknowledgement

The author wishes to acknowledge and thank Dr. Freddie Fryer and Dr. Johan Rens for their comments and editorial contributions.

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Contact Stephen Delport,
Ekurhuleni Metropolitan Municipality,
Tel 011 999-5263,
stephen.delport@ekurhuleni.gov.za

Using low voltage smart system (LVSS) data for intelligent operations and customer support

by Hartmut Bohmer and Haneefa Motani, Util Labs

The LVSS is an end to end system that enables more efficient management and control of electricity consumption and distribution using real time information. For the purpose of demand management, the low voltage smart system (LVSS) was piloted in a residential area in the Gauteng province over the last 4 years. The intent of this paper is to explore benefit cases beyond the initial intent of LVSS and traditional utility use of smart metering systems. The focus is on consumer facing benefits and to use the system as a tool to gain more insight into user behaviour.

Some of the system value added applications include; revenue management, network planning, energy balancing, metering and billing and outage management. Only a small part of consumers have the benefit of falling within the catchment area of LVSS. The paper explores ways and means to provide benefits to the consumer starting in offline or partly locally networked devices. Such an approach would have the option of re-using existing communication channels and thus relax the reliance on the networking part of LVSS while still benefiting from the aggregation and customer portals provided. The consumer preferences with regards to their perceived benefits of online and offline systems to better manage their consumption and appliances is obtained. The paper closes off with recommendations for further research in the area of increasing synergy between different market segments for a greater overall consumer experience and overall benefits realization.

Energy efficiency by behavioural change

The LVSS system is a hierarchical communication network that links electricity measurement points to an in-house display and also to a central monitoring and control server. The LVSS gathers high resolution data. The measurement points are located at the service point where mains power is connected to the premises. The LVSS also relays real time usage data to in-house display called the electricity demand display instruments (eddi).

Initiative 1

As part of a residential demand management pilot, focusing mainly in the Midrand and Lonehill area in Gauteng, end customers were issued with the eddi. The eddi is a plug and play device that shows users their electricity usage for the premises in near real time. Analysing the consumption before and after the issuing of the in-house displays showed a revealing picture. The eddi issuing was done in week 8 till week 11. Energy savings peaked at 10% shortly after the issuing of the displays was concluded and then stabilised at approximately 3 to 4% two months later. This shows that the residents are responding and acting on information that is provided to them. Once people get used to the eddi, the savings percentage reduces.

Initiative 2

On 15 December 2011, SMSs were sent to all customers that were issued with the eddi requesting them to switch off their geysers during the December holiday. A comparison was then done on the amount of geyser reheats between December 2010 and 2011.

Parameters of the study

The analysis was done per mains phase supplied to the premises.

- *Amount of service points:* 820
- *Amount of service points without geyser switching action:* 301 (mostly due to part of the service points being part of a 3 phase supply where one of the phases does not have a geyser)
- *Measurement data:* 23h00 till 03h00
- *Assumption:* Geysers consume >2 kW
- *Assumption:* Many customers go on holiday on 15 December
- *Assumption:* In summer power exceeding 2 kW from 23h00 to 03h00 are geysers

Two approaches of identifying the level of geyser activity were applied. One using a differentiating algorithm to count the amount of geyser reheats and an integration algorithm, which aggregates the energy contained in geyser reheats over the selected period.

Differentiating equation: Geyser reheats are identified when with a running window $P1-P4/(P2-P3) > 800$ W where $P1$, $P2$, $P3$, $P4$ is the average power in successive 5 minute interval. Once a geyser reheat has been identified the detection is disabled for 15 minutes. Trailing edges after 15 minutes count as a second reheat.

The geyser reheat energy is determined by summing of energy for the time duration where

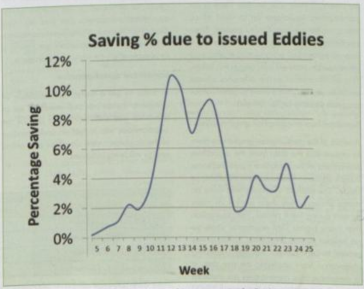

Fig. 1: Savings due to real time consumption feedback.

the power levels exceed 2 kW. The above will also detect high powered air conditioners and under floor heating. The intent of the equations is for trend comparison and not intended for absolute geyser characterisation.

In terms of weather it was confirmed that December 2010 and 2011 had similar climatic temperature profiles so that temperature compensation is not required.

Results from different algorithms

- *Algorithm 1:* Counting the geyser reheat, reduction year on year = 1,5%.
- *Algorithm 2:* Aggregating energy used by geysers, energy reduction year on year = 1,3%.

The conclusion underlined by both algorithms is that SMS communication to consumers to switch off their geysers on a specific date prior to the December holidays has had an insignificant effect. When aggregating the energy used, an interesting observation is that consumers reduced their consumption by approximately 5% in year on year comparison. There is a multitude of driving forces for such reduction. Amongst these initiatives is the issuing of the eddi and the accessibility of web based electricity usage profiles to consumers through the LVSS system.

From the analysis it became clear that the amount of geyser reheats do not equal to the amount of energy that is being used for reheating (Fig. 2). What is interesting to note is that the energy used during 23h00 till 03h00 is largely attributable to non-geyser appliances.

From Fig. 2 one sees a spread of reheat energy of 1 to 8. Part of this can be ascribed to geysers that are forced to reheat at night by timers. It may also be that there is air conditioning equipment on at night which has a similar consumption to geysers. From analysing graphs of the raw data manually, it was confirmed that a big spread of efficiency gains can be achieved from geyser insulation. The information of geyser efficiency spread could be used to plan a more targeted rollout program yielding higher benefits.

Scenarios from consumption graph analysis

Analysis of the consumption graphs was done to ensure that the data from the algorithms was correct. At the same time it provided some insight on the correctness of the assumptions made. The analysis of graphs was done on mains phases where there were 1 or more reheats during the 4 period. The assumption that many higher LSM residential users go on holiday during December holidays was proven to be incorrect. Another interesting observation from analysing the raw data is to determine how many timers are installed that push out reheats into the period 23h00 till 03h00 and how many geysers are off the grid.

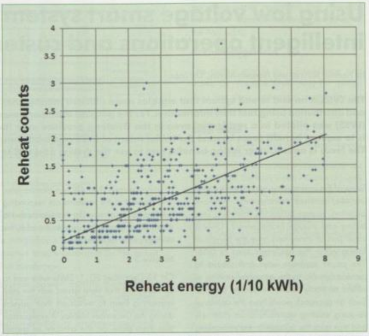

Fig. 2: Average reheat counts and reheat energy (1/10 kWh) per mains phase from 23h00 till 03h00 during December 2010, 2011 (excluding phases where no geyser was detected).

The analysis of the raw data in graph form confirmed the results from the algorithms that the amount of people acting on 16th on the SMS campaign was neglible. However it was noted that people had already switched off their geysers before the SMS was sent in December 2011. In December 2010 however, less users had switched off their geysers. This could be attributed to the various power awareness campaigns that had occurred throughout the year. Multiple communication initiatives and price increases are having a noticeable effect on consumer behaviour.

Consumer questionnaire

In order to get a better understanding of consumer behaviour and needs, a list of questions was distributed. The aim of the questionnaire was to get an understanding of the consumers view on offline and online energy efficiency initiatives.

Questionnaire findings

- If you had access to a tool that breaks down the costs of your appliances so that you can make more informed decisions on whether to install items such as a geyser blanket, solar geyser, LED lights etc. would you use it? (Yes: 98%)
- Would you be more willing to invest in home improvements that save power if you can see a definite reduction in your electricity bill? (Yes: 100%)
- Would you be interested in enjoying the added feature of having a remote energy analysis done on your household to determine if your appliances are working efficiently? (Yes: 81%)
- Would you install a "smart" timer that can detect when you're at home (via the Bluetooth on your cell phone) to ensure that your geyser is switched on? *Note this could reduce your insurance premium as there is no risk of geyser failure while you're away so your

	Total – geyser in 1/10 of kWh	Geyser energy in 1/10 of kWh	Reheat counts
2010 first half of December	17,58	2,56	0,67
2010 second half of December	17,87	2,27	0,60
2011 first half of December	16,66	2,45	0,68
2011 second half of December	17,07	2,15	0,60

Table 1: Average non-geyser load, geyser load and geyser reheat counts from 23h00 – 03h00 (including phases where no geysers were detected).

response time to the damage is much quicker. Timer/occupancy aware smart timer/no timer (36%, 47%, 16%)

- Do you react to the Eskom power alert messages (Yes: 85%)

What is clear from the questionnaire is that the more internal the locus of control that is provided to the customer the higher the acceptance. Options that reduce the customer's level of control have lower preference levels. One item where customers differed on whether it provides them a higher internal locus of control was the comparison of the smart timer compared with a normal timer. The benefit of automation however convinced the larger number of participants to rate the occupancy aware smart timer as being their preference.

Point by point analysis

- Would consumers use tooling if available to them, to assist them in improving on appliance level efficiency (98%), Different tools exist on the market that measures the consumption of appliances. Both plug based and distributed board (DB) based products are available: Part of the analysis work for the paper was done in an area that has no LVSS coverage. A smart phone application that uses the magnometer to sense current flowing in its vicinity was used. The accuracy provided is sufficient for energy efficiency base lining and improvements. Offline measurement capabilities like these when packaged and marketed appropriately may address a certain need in the market.
- *Will invest in home improvements when I can see direct savings in the electricity bill (100%):* In the general comments field of the questionnaire, a few of the consumers elaborated on their energy efficiency measures they had implemented (switching to heat pumps and solar geysers). One response highlighted the need for a business model and switching support to alternative sources for energy other than for geysers only. Smart phones have significant processing power to plug the captured data into different models which can reside on the smart phone or pulled on demand into the smart phone. Due to operator detection, the conversion of electricity consumption to cost can be automated, simplifying the interpretation of information
- *Appliance level efficiency analysis results available from a central server (81%):* With accurate per premises data one can target specific non-efficient geyser owners. One may be able to convince more people by being able to show them the before and after results. One concern that shimmers through with the result is that some people may be hesitant to use this service due to privacy and/or technological complexity concerns.

Initiative	Utility benefits	Consumer benefits	Insurance benefits	LVSS potential benefit	Comment/ recommendation
SMS campaign to switch off geyser by utility	Low*	Medium*	Medium*	Measurement	Campaign should potentially be done jointly by insurance company and utility for higher uptake
Timer	High	Low	Potentially negatively affected*	M&V for RMR rollout	Increased potential of geyser failure when person not at home due to reheat shifting out of peak time
Offline smart timer, phone appliance measurement	High	Medium Measurements, alerts	Potentially negatively affected*		Customer gets more benefits measurement from smart timer. Should be considered
Offline occupancy aware timer	Medium – More load when the consumer is at home	Medium May not have enough time to heat up	Medium*		May be in conflict with online due to security concerns Could be considered as an intermediate step prior to full networking
Part time online timer using smart phone as carrier	Medium* Quality of service info Fast rollout, low existing comms network	Medium* Can view information on web consoles. Negative	Low* Can obtain measurement information to audit claims	Quality of service for utility Consumer portal and smartphone gateway Audit info for insurance	Could be considered as an intermediate step prior to full networking
Online smart timer through PLC network	Large* On demand load shifting and quality of service	Medium* Remote control of appliance and online consumption Negative due to ceding control, privacy concerns	Medium* Can obtain measurement information to audit claims	Consumer portal and smart phone gateway, Network and load management	Will need additional agreement/ communication with consumer as whether and when online control may be used
Secure transaction/ identity tokens sent to online timer in premises		Medium*			Future benefits for more secure identity management in the online world

Table 3: Optimising convergence benefits to different stakeholders from offline automation to networked appliance control connectivity. The items that are starred(*) need further study to fully quantify.

- *Timer/occupancy aware smart timer/no timer (36%, 47%, 16%):* Although only available to date in concept, consumers instinctively approve of a "smart timer" that can sense premise occupancy and only switch on heavy users when someone is at home using proximity sensing. Consumers are interested in this option especially if there is a monetary benefit due to a reduced financial cost/risk in the case of geyser failure. Besides better management of a geyser failure, switching off the geyser when no one is at home will also result in electricity savings. How substantial the reduction of geyser failures is when electricity is being switched off when no one is at home would be a subject for a further study. The high level of interest in automation of geyser switch-off and switch-on is also an indication that consumers prefer mundane tasks to be automated.
- *Power alert information:* A surprisingly high number of consumers that responded to the questionnaire indicate that they

respond to power alert information by switching off appliances in the house. There was a request to make the power alert information available on the eddi. With a lot of the younger generation using the internet more than the TV, showing the power alert on an interface rather than the TV such as the eddi would make sense. Have not mentioned what they switch off (will provide insight into what consumers deem as heavy users)

Using the LVSS data for operation and maintenance

The LVSS gathers high resolution reading data. The measurement points are located at the service point where mains power is connected to the premises. Monitoring of normal geyser operation can be done through geyser reheat analysis especially in cases where there are repeatable detectable reheat occurrences. It will work well if there is no interference with appliances that exhibit similar switching profiles and power use as for instance under floor heating.

"Smart timers" are a natural candidate for optimising geyser lifetime operation. If a geyser is on for a period longer period that say 6 hours while it was operating normally before, it is a likely sign of a fault condition. Smart timers with a buzzer can alert such conditions. Risk of geyser failures occuring while no one is at home may be reduced by deploying "smart timers" that are aware of the occupancy of the premises. Only switching on the geyser when people are at home may be a way to reduce consequential damage due to quicker attendance to the fault condition by residents.

Table 2 provides a breakdown of options of how to serve the interests of different stakeholders with different offline and online based appliance management solutions.

Conclusion

The LVSS system provides additional value which can be unlocked through automatic and manual analysis of the fine grained reading data. Different parties i.e. utility, consumer and third parties for example, insurance companies, may benefit from the data. However there are rollout speed and cost impacts to rollout an end-to-end system with its own communication system. Also having measurement and control on the appliance provides direct information reducing the need for complicated analysis and verification of reading data in agregate form. A further benefit of consumer focused solutions is that these may be applicable in larger markets than just the South African context. Smart grid technologies have quite a lot of country dependencies. A combination of top down rollout of LVSS and a bottom-up approach of rollout of appliance control devices, such as the "smart timer", that may be networked in future may be an approach that allows value to be unleashed quickly, meeting the needs of different stakeholders.

The emergence of smart phones and their networking capabilities opens up another opportunity namely part time network access. Using smart phones as the carrier for measurement information to a central LVSS reduces the need for custom communication networks and thus faster rollout. Privacy and cost of transmission are issues that may impede consumers opting for relaying information through their smart phones. Exploiting benefits associated with convergence between service sectors may be a topic for further study i.e. installation of appliance control units that benefit the utility, consumer and insurance industry all interfacing to one common platform.

Contact Hartmut Bohmer,
Util Labs, Tel 011 805-0094,
harmut.bohmer@utillabs.com

Cellphone technology for asset management and its impact on operational efficiency

by Ignatius van Zyl, Touchwork

This paper outlines solution requirements and mobile technology best practices for the municipal sector, focusing on managing a diverse physical asset portfolio and related services.

Assets can take a variety of forms: financial, physical or intangible. Whatever form assets take, there are generally three guiding features which determine what constitutes an asset – it will have a value, it will provide benefits from its use over the period of its useful life, and is central to the organisation's business processes.

A business process is a collection of related, structured activities or tasks that produce a specific service or product (serve a particular goal) for a particular customer or customers.

Public sector – in the news

"Government is focused on accelerated public sector reform. They need to improve the lives of citizens, boost investor confidence and become the catalyst for sustainable success stories in Africa. We are aligned to assisting government to be at the forefront of this reform." – Yunus Naidoo, Public Sector Leader – Advisory

Around the world, governments are faced with an increasingly complex array of asset management challenges. At the same time there is an increasing demand for transparency and accountability on public policies.

Asset-intensive organisations within the municipal sector struggle with collecting accurate real-time information about asset performance, workforce status, and field conditions.

The diversity of physical assets and service providers that the municipal sector is faced with is making the task of creating sustainable success even more difficult. Physical assets span over a wide array of asset classes, i.e. vehicle fleets; facilities such as parks, or water/wastewater treatment plants; and linear assets like electrical, road and sewer systems. Aligned with the array of physical asset classes are the dissimilar service providers to be managed.

Despite the accelerated need for a holistic lifecycle physical asset management program within the municipal sector, the prevailing approach continues to rely on paper-based data collection and field communications or multiple standalone systems and spreadsheets. The resulting business processes are unmanageably complex and inaccurate, making it impossible for management to entrench best practices. Further to this, technical teams and other key asset management resources are prevented from making proactive and cost-effective decisions.

Compliance, safety, and productivity all suffer as a result.

Asset productivity and reliability – the critical element

The overriding objective for most asset intensive industries, such as the municipal sector, is comfortably concluded to be customer satisfaction in most cases. This premise however can be academic in its pursuit, as the customer may be too far removed from the actual objective to drive daily field operational aspects.

With physical assets at the core of asset intensive businesses, the priority pursuit is and will remain to be the delivery of high asset productivity directly linked to uninterrupted service and production.

This in turn, depending on the industry and the end customer, ensures profitability, asset life prolongation, and so forth. For the municipal sector, it means ensuring the community has the foundation upon which to conduct commerce freely and without interruption, and assurance of public safety.

In the next section of the paper we provide an introduction to the PAS 55 standard, advances in the mobile arena, and describe how the convergence of mobility and a well structured physical asset management program can deliver competent governance of critical assets and ultimately world-class service delivery to customers.

PAS 55 – "A way of performing asset management"

It became clear to the Institute of Asset Management (United Kingdom) that there was a crucial need to provide a consistent framework for physical asset management. In a quest to develop risk mitigation strategies and best practices focusing on critical assets, the Institute of Asset Management and the British Standards Institute (BSI) worked together to develop the publicly available specification (PAS) 55-1: 2008: Asset Management, first published in 2004.

PAS 55 is becoming internationally accepted as the industry standard for quality asset management. In a nutshell, the PAS 55 standard acts as a valuable guideline for asset lifecycle management, compliance, and quality control, and is typically relevant to all asset intensive industries.

PAS 55 defines asset management as *"systematic and coordinated activities and practices through which an organisation optimally and sustainably manages its assets and asset systems, their associated performance, risks and expenditures over their lifecycles for the purpose of achieving its organisational strategic plan"*.

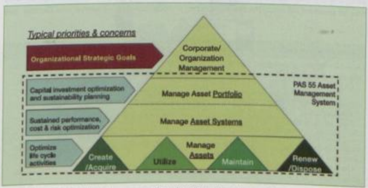

Fig. 1: The typical priorities and concerns evident when integrating and managing assets and asset systems

Assets can be identified and subsequently managed at different levels – ranging from discrete assets to complex asset systems or diverse asset portfolios. Fig. 1 shows examples of priorities and concerns that might be evident at the different levels of asset integration and management.

The PAS 55 standard focuses on all asset types, varying from critical physical assets to human assets. The physical assets are divided into the following four classes:

- Plant and production (oil, gas, chemicals, pharmaceuticals, food, electronics, power generation),
- Infrastructure (railways, highways, telecommunications, water and wastewater, electric and gas distribution),
- Mobile assets (military, airlines, trucking, shipping, rail), and
- Real estate and facilities (offices, schools, hospitals).

In review of Fig. 1, it is also clear that the PAS 55 standard extends further than just the maintenance of physical assets.

PAS 55 implementation and active utilisation success is determined by the level of organisation-wide integration. The first step would be to establish the foundation of existing data on assets – ranging from condition and performance to costs and opportunities. Further to this, the implementation should also be focused on intangible assets (e.g. social impact) and the financial aspects (e.g. asset lifecycle costs) of the organisation.

Applicability of PAS 55 to the municipal sector

For the municipal sector similar to other asset intensive industries, optimal asset performance and productivity form the basis of their long term business objective. The asset lifecycle for these industries are characterised by high initial investment, maintenance and associated risk – starting at planning/renewal and ending off at disposal phase. Additional to the asset lifecycle, another strong driver is regulatory accountability for asset and service safety management. Embracing the PAS 55 standard will empower the municipal sector to align their asset management strategy and approach with the overall business strategy.

The PAS 55 approach – PDCA cycle

In order to ensure optimal physical asset management – as per PAS 55 outline – a lifecycle approach needs to be taken. This approach will be driven by key decisions related to asset acquisitioning, applicable and best practice maintenance and utilisation, and ultimately the disposal thereof.

The PAS 55 approach to lifecycle physical asset management is based on a plan-do-check-act (PDCA) cycle to ensure continuous improvement.

The components of the PDCA cycle are (subscribed to the PAS 55 standard):

- *Plan:* Physical asset management strategy, policy, objective and plans to be established.
- *Do:* Identify key physical asset management enablers (e.g. FM and EAM software) and ultimately implement the physical asset management strategy defined during the plan stage.
- Check: Monitor, measure and report against the KRAs established during the plan stage.
- *Act:* Act upon the check stage results to achieve, and improve on objectives and plans set out.

Within the PDCA cycle PAS 55 defines a few key elements, they include:

- *Asset management policy:* Strategic direction for physical asset management – aligned with corporate goals and objectives.
- *Asset management strategy objectives and plans:* Act as enabler for pro-active problem resolution within the physical asset management space.
- *Asset management enablers:* Key accountability to ensure organisational buy-in.

Mobility in the context of the enterprise

In review of recent mobility surveys done by Accenture, IDC, Forester and Gartner (see Table 1 for more details), we see that history is repeating itself on the technological front. Mobile devices transitioned from being a secondary-use device to a primary-use device. This transition has presented companies with new possibilities – new platform, new purpose, whether devices are supplied by the organisation or employees make use of their own. Although the mobility era brings an astonishing number of capabilities, it will not be without its challenges and therefore companies need to carefully plan and execute mobile strategies.

Analysis and trends	Survey results
Number and type of connected device is dramatically changing – *IDC Forecast*	• 1B smart phones and 1.2B mobile workers by 2013. • Large enterprises expect to triple their smart phone user base by 2015.
Mobility is driving the "consumerisation" of IT – *Forrester Forecast 2010/2011*	• 46% of large enterprises supporting personal owned devices. • Billions of downloads of 500 000 apps from Apple app store.
Increasing demand for enterprise applications – *Gartner and Forester Analyst Calls (Oct 2011)*	• 20% of mobile workers are getting business apps from app stores today. • 50% of organisations planning to deploy mobile apps in 12 months.

Table 1: Mobility in the context of the enterprise trends.

The device and business process evolution

The mobile industry is at the doorstep of the next big change – this change will comprise a three-force convergence, namely:

- True mobile broadband.
- Mobile devices with similar functionality as computers.
- Software applications to improve on workforce productivity.

Mobile penetration statistics reveal that there are nearly 6-billion mobile phone subscribers and nearly all new phones connect to the web. Also on the "mobile table" is the worldwide adoption of tablets – with strong evidence to indicate that tablet sales will exceed laptop sales by 2015/16. Sales revenue on mobile applications is projected to reach R427-billion by 2016.

Mobile adoption rates are driven extensively by technological advances – ranging from better and more user-friendly mobile operating systems, to receivers and processing units achieving wider network coverage and faster connectivity.

The mobile platform now brings new meaning to the concept of "always-on" – delivering pervasive access with secure cloud based transactional processing.

Another key technological advancement within the mobility arena is versatility. Sensor technology has long surpassed GPS and Bluetooth connectivity to include motion, altitude and vital signs sensing.

Key vendor software development is also focused on device independency – enabling smart phone to wide screen projection without loss in data connectivity (see Figs. 3 and 4).

Advances in mobile technology – the asset management imperative

In review of the section above – focused on the evolution of mobility – organisations have realised that the advances in smartphones and other mobile devices are transforming them from channels of convenience to the primary means of communication/

interaction. Mobility will not just connect more of the marketplace to the web, but also offers advantages previously impossible in the physical asset management space. By putting mobility at the heart of their physical asset management processes, companies will better engage with both customers and employees. In order to embrace mobility as a key enabler for asset-intensive physical asset management, mobile solution providers need to address connectivity, security, location and identification, and data orchestration requirements.

Adaptable connectivity

Advanced mobile solutions offer access to business critical data through all modes of communication – ranging from connected, disconnected to intermittent connectivity modes.

A municipal worker or contractor in the field cannot always rely on uninterrupted wireless communications. In many instances uninterrupted communication is simply not possible (e.g. remote locations), not safe or against strict regulation. These remote workers should be able to effectively execute their assigned work orders, operating in disconnected mode, and later receive updates and/or provide feedback when wireless coverage is re-established.

In connected or otherwise referred to as real-time mode, the field worker should be able to enter emergency work orders, request spares, gain access to critical technical objects (e.g. standard operating procedures), record assessment results, and dynamically pass alerts or alarm notifications between the field force and the physical asset management system.

The adaptable connectivity requirement also extends to the disconnected mode of operation, where field workers will synchronise work orders and other critical asset information (while connected) to their mobile devices. All work-performed data (e.g. labour performed details, failure data, etc.) will then be entered locally into the mobile device. The recorded data will then later be synchronised once connectivity is re-established.

Another key requirement within the physical asset management area for the municipal sector is the requirement to ensure worker productivity even with inconsistent network access.

Advanced mobile solutions with dynamic recovery functionality, make provision for remote workers to continue executing their assigned work orders even when the network service is interrupted.

Security

For long, business-specific mobile adoption has been hindered, because of transactional security requirements that could not be met at the time. Advanced asset management mobile solutions are characterised by:

- Support for SSL, HTTPS, and PKI security standards for 802.11 wireless networks.
- Mobile security measures integrate seamlessly into the enterprise application's security architecture.
- Transactional security requirements are met with bi-directional authentication via digital security certificates and/or passwords.
- Data transmitted bi-directionally, and stored locally is fully encrypted and locked.
- Data and modular access is controlled with user logins and profiles.

Another key driver for security within the physical asset management space and even more so the municipal sector, is the requirement for across-all-stakeholders collaboration in the field.

Location and identification

Thousands of industries worldwide have successfully employed geospatial information management (GIS) and field force automation (FFA) technologies as value business drivers.

During the past five to six years, we have seen a convergence of these technologies primarily focused on improved resource and physical asset management.

Location and identification functionality both automates the collection of information and provides an audit trail.

- *Bar codes and RFID tags:* Workforce context on approaching physical assets, and workflow facilitation.
- *Scanning a bar code or sensing an RFID tag:* Referencing the technical object database.
- *GPS:* Asset and workforce context and route optimisation.

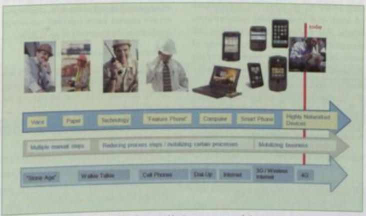

Fig. 2: The device and business process evolution.

Fig. 3: One size fits all?

Data orchestration and collaboration

A successful mobile asset management solution can dramatically improve the silod data and operations approach within the municipal sector. The mobile platform should enable across department/area communication and visibility – ranging from the back office, to the mobile worker, and among mobile workers and contractors.

Data orchestration requirements are met with the mobile platform supporting standardised integration options, business process workflow and data mapping.

Key drivers for asset service organisations

The business challenges and strategic objectives of field service and asset intensive organisations are not mutually exclusive – in fact decision-making factors are often the same with difference only at the degree and emphasis level.

In order to identify the key business drivers for the municipal sector, the first step would be to define the key divisions of work and their related requirements. While this certainly oversimplifies the demands, dynamics and complexity of each division, there are three overarching divisions of work that the municipal sector must manage:

- *Customer services work division:* Includes everyday field work typically unplanned and completed within a shorter duration.
- *Inspection and maintenance work division:* Includes field work around managing and maintaining assets during the 'operate' phase of the asset lifecycle.
- *Project work division:* Includes long-cycle work that must be planned, designed, scheduled and executed over longer periods of time.

Fig. 4 depicts the relationship of key business drivers for asset vs. field service organisations.

The following challenges/business drivers are forcing the municipal sector to take a fresh look and seek mobile solutions that address their unique pressures and priorities:

Low productivity – 30% improvement potential

Many organisations have already automated asset lifecycle back office processes. The associated field work is however still largely dependent on paper-based processes, ineffective communication channels, and limited documentation of industry and asset specific know-how (due to an aging and retiring workforce).

Without the right tools, work orders take longer to close off, productivity suffers and workload balancing becomes an impossible task.

Without a mobile solution focused on physical asset management field activity, overall productivity can suffer by as much as 40%.

Potential benefits to be realised with mobile automation:

- Field workers to gain access to technical objects related to specific work to be performed.
- Work instructions and asset history can be viewed on site.
- Decentralise decision making to field workers on-site.
- Emergency service can be requested immediately for an unexpected outage.
- On site access to operating and fault finding guidelines/procedures.
- Data captured power back office decision-making (e.g. workload balancing).
- Quicker response times.
- Productive "wrench time" is significantly increased.

While an organisational change towards mobility as key enabler for physical asset management is not without its challenges, recent surveys have reported workforce productivity improvements of up to 30%.

High costs – 25% savings potential

When companies employ mobility as a key field enablement tool, significant cost savings can be realised. These cost savings are the sum effect of:

- Shortened planning cycles
- Quicker response times
- Reduction in maintenance rework
- Overtime reduction
- SLA compliance – avoid fines
- Excessive reliance on contractors

Visibility not optimal – 50% improvement potential on field work visibility

A recent survey conducted by ARC revealed that asset intensive organisations have incomplete data on as much as 75% of all field work. The primary reasons for the lack of the visibility include:

- Unknown field personnel location information.
- Field workers only to submit work order paperwork at the end of their shifts – resulting in inaccurate and out dated information.
- Field workers often detect and repair problems outside of a work order's scope – resulting in inaccurate asset and work performed data.

Potential benefits to be realised with mobile automation:

- Bi-directional communication and full-circle visibility across the enterprise.
- Data and communication occur in real-time.
- Geographic positioning system (GPS) and geographic information system (GIS) capabilities can optimise field work response time and improve on safety compliancy.
- Accurate asset and failure analysis data.
- Operational data at the manager's fingertips – actionable intelligence (predictive analytics), improved decision-making.
- Improved asset uptime – translates to reduced maintenance costs.

Governance and compliance a priority – 25% improvement potential

Well-structured physical asset management is central to regulatory compliance and accountability for asset intensive industries. A well-managed technical document repository

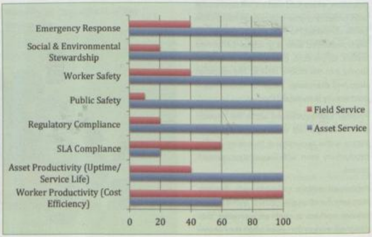

Fig. 4: Key business drivers comparison chart – asset service vs. field service.

forms the basis upon which organisations meet regulatory guidelines and public expectations for safety and environmental impact.

For the municipal sector, as with many other asset intensive industries, sound governance and compliance begin in the field. The biggest hurdles in improving governance out in the field are inaccurate data collection and lacking audit trails.

Potential benefits to be realised with mobile automation:

- Real-time, time-stamped data recording.
- Data validation at the point of entry – improvement in regulatory reporting.
- Behaviour enhancement in terms of field workforce productivity and safety.
- Improved and simplified access to the "right" information – no need to consult a hard copy manual.

The PAS 55 standard has earned broad acceptance, with development spanning over fifty public and private organisations. It represents a huge stride forward in improving municipal sector specific governance and compliance requirements.

Health and safety concerns – focused improvement potential

Paper-based work orders, safety procedures and checklists are still at the order of the day for many asset intensive industries. In the field, work is carried out with paper-based work orders and hard copy manuals – utilising two-way radios if assistance and or spare parts are needed. In instances where field workers do not have access to radio communication, they are to rely on their own knowledge and experience. This scenario in many cases drives a rift between regulatory compliancy and the workforce.

Potential benefits to be realised with mobile automation:

- Health and safety process efficiency improvement.
- Enhanced planning and scheduling – availability, proximity, skill set and certifications.
- Real-time data – status updates, technician location.
- Route planning and optimisation – safest and shortest.
- Work safety guidance – factoring actual conditions and proven methodologies.
- Compliancy – appropriate skills and certifications.
- Automated risk assessment, workflow approvals and safety checklists.

PAS 55 compliance

Manage risk proactively

The PAS 55 standard mandates mitigating risk before it becomes a problem, versus addressing risk after the fact with root cause analysis.

Potential benefits to be realised with mobile automation:

- Risk assessment build into the mobile application as standard function across all modules – work orders, alarms, defects.
- "Start by" and "complete by" dates calculated automatically according to work prioritisation.
- The work order mobile application can also trigger follow-up tasks based on alarm criteria set.
- The application can also display the last audited results, related to the specific asset in question.
- Record failure analysis data.
- Actionable intelligence on defects and risks posed to the business.

Asset condition assessment

PAS 55 requires responsible asset owners to know the current condition of each asset.

Potential benefits to be realised with mobile automation:

- Asset condition is automatically calculated and updated based on audit responses.
- Support for complex and enterprise wide asset inspections/audits.
- Follow-up actions – new work orders – are automatically triggered based on audit responses.

Standardise the asset register administration business process

The PAS 55 standard provides guidelines for establishing and maintaining an effective electronic asset register. An effective electronic asset register consists of three key elements, namely:

- Complete history on all asset related work orders – defects, failure analysis, work performed and costs.
- Hierarchical structure – parent assets, components, associated equipment, tasks, spares.
- Flexibility in accommodating changes/ updates.

Potential benefits to be realised with mobile automation:

- Facilitate an effective asset register – collecting asset data aligned with PAS 55 guidelines.
- Regular updates of unregistered asset data (scheduled audits) – ensuring data integrity.

Health and Safety concerns – focused improvement potential

Paper-based work orders, safety procedures and checklists are still at the order of the day for many asset intensive industries. In the field, work is carried out with paper-based work orders and hard copy manuals – utilising two-way radios if assistance and or spare parts are needed. In instances where field workers do not have access to radio communication, they are to rely on their own knowledge and experience. This scenario in many cases drives a rift between regulatory compliancy and the workforce.

Potential benefits to be realised with mobile automation:

- Management perspective
  - Health and safety process efficiency improvement
  - Enhanced planning and scheduling – availability, proximity, skill set and certifications
  - Real-time data – status updates, technician location
- Technician's perspective
  - Route planning and optimisation – safest and shortest
  - Work safety guidance – factoring actual conditions and proven methodologies
  - Compliancy – appropriate skills and certifications
  - Automated risk assessment, workflow approvals and safety checklists

Conclusions and outlook

An intense examination of the topic "mobility as key physical asset management enabler within the municipal sector" shows that mobile-technology based solutions are already widely adopted all over the world. With ongoing mobile development and exponential market increase, we expect the trend of mobile adoption to further intensify. The importance of mobility is substantiated by the various activities in the field of municipal physical asset management. So far, this paper has provided a detailed overview of current trends, industry specific drivers identified and an outlook to potential solutions. In this section, the core findings of this paper are summarised.

Core findings

In the municipal sector financial success is directly linked to physical asset reliability and productivity. Well-structured asset management programs can dramatically impact the overall performance and useful life of these physical assets.

Accordingly, municipal sector responsible asset owners are continually trying to improve their maintenance practices.

Based on extensive research done, we know that asset intensive industries have been underserved for decades with solutions and mobile technologies. Due to the following trends these industries are now forced to take a fresh look at physical asset management mobile solutions that address their unique pressures and priorities:

- The global economic crisis – reduction in revenues and available capital.
- Ageing and retiring workforces – knowledge retention.
- Ageing infrastructure and increased demand.
- Carbon footprint advocacy – environmental impact.
- Increasing public scrutiny forcing increasing regulation.
- Regulatory compliance necessitates optimised business processes.
- Security demands.

The municipal sector must thus increasingly seek mobile physical asset management solutions that enable their field workforce to:

- Proactively perform physical asset management – based on early detection.
- Respond more quickly to maintenance events.
- Perform planning and scheduling based on real-time resource availability and location awareness.
- More effectively enforce safety standards.
- Respond more organically to changing priorities.
- Mitigate asset failure risk more effectively.
- Increase regulatory compliance levels.
- Increase asset life – physical asset longevity.
- Ensure operational continuity.

"Email marketing reports" research has shown that mobile device use has increased from just 750 000 mobile subscribers in 2001 to roughly 5-billion subscribers in 2011. By 2015, mobile devices will become ubiquitous, as research analysts predict their use will increase fifty fold.

Directly aligned with this growth spurt, the physical asset management enterprise mobility market has evolved dramatically since 2008/9 – starting off from simplistic data collection to integrated enterprise solutions focused on automating complex asset management processes.

In closing

This paper validated that given various market drivers in play, mobilising the asset oriented/ long-cycle work remains an untapped opportunity for the municipal sector.

The opportunity is now…

Mobile solutions purpose-built for asset intensive industries can provide a huge opportunity to:

- Ensure worker safety through adherence to best practices.
- Decrease maintenance costs through optimised workforce utilisation.
- Create a preventative asset management business mentality throughout the organisation.
- Improve service delivery and productivity through real-time access to asset information.
- Remove information silos to further drive across-all-stakeholders collaboration
- Improve operational efficiency.
- Achieve better field service responsiveness.
- Reduce costs.
- Ultimately realise a greater return on assets (RoA).

Mobility and program-driven asset management has become core to every industry. It is transforming business-to-consumer, business-to-business and business-to-employee relationships. This convergence phenomenon is fast becoming table stakes for the municipal sector to achieve sustainable success, and improved operational efficiency.

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Contact Ignatius van Zyl,
Touchwork, Tel 021 700-3501,
ignatius@touchwork.com

AMEU Engineering Members

Organisation	Name	Address	Phone	Fax
Abaqulusi Municipality	Ken Tupper	P O Box 57, Vryheid, 3100	034 982-2133	086 645-2165
Amahlathi Local Municipality	JC Moerdyk	Private Bag X4002, Stutterheim, 4935	043 683-5014	043 683-2577
Beaufort Wes LC	Roelof van Staden	Private Bag 582, Beaufort Wes, 6970	023 415-2276	023 415-2276
Bergrivier Municipality	Arthur Willemse	P O Box 60, Piketberg, 7320	022 913-8020	022 913-1082
Bitou Local Municipality	Lawrence Msibi	Private Bag X1002, Plettenberg Bay, 6600	044 501-3277	044 533-3487
Blue Crane Route LC	Elsa Vermeulen	P O Box 21, Somerset East, 5850	042 243-1333	042 243-2260
Breede Valley Municipality	Willem Albertyn	Breede Valley Municipality, Worcester, 6850	023 348-8000	023 348-8073
Buffalo City Municipality	Robert Ferrier	P O Box 2001, Beacon Bay, 5205	043 705-9601	043 748-3748
Camdeboo Municipality	Albertus van Zyl	P O Box 71, Graaf-Reinet, 6280	049 892-2121	049 891-0066
Cape Agulhas Municipality	Pieter Everson	P O Box 51, Bredasdorp, 7280	028 425-5500	086 521-5621
Cederberg Municipality	Jacob van Zyl	Private Bag X2, Clanwilliam, 8135	027 432-1112	027 432-1901
Cenored	R Bauer	P O Box 560, Otjiwarongo, Namibia	+264 67 30470	+264 67 30770
Centlec	Leon Kritzinger	Private Bag X14, Brandhof, 9324	051 409-2428	051 409-2376
City of Cape Town	Denise John	P O Box 82, Cape Town, 8000	021 637-1333	021 638-4642
City of Tshwane Metro Municipality	Nndwamato Mutshidza	P O Box 423, Pretoria, 0001	012 358-4184	086 214-4478
City of Windhoek	Ferdinand Diener	P O Box 5011, Windhoek, Namibia	+264 61 290245	+264 64 290249
City Power	Sicelo Xulu	P O Box 38766, Booysens, 2016	011 490-7511	011 490-7362
Coghsta	Casper Schoeman	Private Bag X5005, Kimberley, 8301	053 807-2827	053 807-2815
Copperbelt Energy Corporation	Emmanuel Katepa	P O Box 20819, Kitwe, 10101	+260 022 4400	+260 224 4611
Department of Local Government Western Cape	Porsher Mashaboko	Private Bag X9076, Cape Town, 8000	021 483-3958	021 483-5783
Ditsobotla Municipality	Charles Geldenhuys	P O Box 7, Lichtenburg, 2740	018 632-5051	018 632-3438
Drakenstein Municipality	Anthea Du Preez	P O Box 1, Paarl, 7646	021 807-4661	086 645-7107
Ekurhuleni Metropolitan Municipality	JJ Roos	P O Box 215, Boksburg, 1460	011 861-2404	086 638-1977
Emadlangeni Municipality	Ryno Els	P O Box 11, Utrecht, 2980	034 331-3041	034 331-3867
Emfuleni Local Municipality	Evert van Helden	P O Box 3, Vanderbijlpark, 1911	016 986-8363	086 555-5981
Emnambithi / Ladysmith Municipality	Electricity Dept	P O Box 56, Ladysmith, 3370	036 637-6905	036 637-2592
Emthanjeni Municipality	Patrick Tshowe	P O Box 42, De Aar, 8780	053 632-9100	053 631-1518
Endumeni Local Municipality	Mark Donaldson	Private Bag X2024, Dundee, 3000	034 212-2224	086 568-9622
Ephraim Mogale Local Municipality	Johan Durie	P O Box 111, Marble Hall, 0450	013 261-8454	086 605-2147
Erongo Regional Electricy Distributor Company	Robert Kahimise	Erongo Red, Walvis Bay, 9000	+264 64 214600	+264 64 214601
Eskom Distribution	Peter Craig	P O Box 66, New Germany, 3620	031 710-3516	031 710-5288
eThekwini Electricity	Rosemary Naidoo	P O Box 147, Durban, 4000	031 311-9006	031 311-3196
Ga-Segonyana Municipality	Lucas Monyela	Private Bag X1522, Kuruman, 8460	053 712-9372	086 635-6266
George Municipality	Thys Meyer	P O Box 19, George, 6530	044 801-9249	044 874-3936
Govan Mbeki Municipality	December Miya	Private Bag X1017, Secunda, 2302	017 620-6283	086 645-4809
Greater Giyani Municipality	G Masingi	Private Bag X9559, Giyani, 0826	015 811-5542	086 587-8109
Greater Kokstad Municipality	Mhlengi Sangweni	P O Box 8, Kokstad, 4700	039 797-6675	039 727-3676
Greater Tzaneen Municipality	Carin Biewenga	P O Box 2455, Tzaneen, 0850	015 307-8162	015 307-8028
Hessequa LC	Gert Maris	P O Box 29, Riversdale, 6670	028 713-2412	028 713-3704
Hibiscus Coast Municipality	Chief Electrical Engineer	P O Box 5, Port Shepstone, 4240	039 688-2000	039 682-1131
Kai Garib Local Municipality	Andrew Wells	Private Bag X6, Kakamas, 8870	054 461-6470	054 461-6401
Kannaland LC	Carina Horn	P O Box 30, Ladismith (Kaap), 6655	028 551-1023	028 551-1766
Khara Hais	Hennie Auret	Private Bag X6003, Upington, 8800	054 338-7145	054 338-7337
Knysna Municipality	Leonard Richardson	P O Box 21 , Knysna, 6570	044 384-0422	044 384-1816
Kouga Municipality	Theo Madatt	P O Box 21, Jeffreys Bay, 6330	042 200-2742	086 536-4360
Kungwini LC	Mafemani Moswanganyi	P O Box 40, Bronkhorstspruit , 1020	013 932-9560	086 639-5837
Kwadukuza Municipality	LF Klopper	P O Box 72, Kwadukuza, 4450	032 437-5087	032 551-5500
Langeberg Municipality	Johan Rossouw	Private Bag X2, Ashton, 6715	023 626-4960	023 626-5532
Lekwa LC	Dawie Lottering	P O Box 66, Standerton, 2430	017 712-9819	017 712-9816
Lephalale Municipality	Sbongile Ditselo	Private Bag X136, Lephalale, 555	014 763-2193	014 763-5662
Lesedi Local Municipality	Hennie Coetsee	P O Box 201, Heidelberg, 2400	016 340-4308	086 655-2714
Lukhanji Municipality	Pieter Bezuidenhout	Private Bag X7111, Queenstown, 5320	045 807-6000	045 839-7545
Madibeng Local Municipality	Jacobus Lukas Mynhardt	P O Box 106, Brits, 0250	012 318-9361	012 318-9203
Makana Municipality	Johnson Siteto	P O Box 176, Grahamstown, 6139	046 603-6062	046 622-5264
Makhado Municipality	Ems Joubert	Private Bag X2596, Louis Trichardt, 0920	015 519-3019	015 516-5084
Maletswai LC	SJ Mosenene	Private Bag X1011, Aliwal North, 9750	051 633-2406	051 633-2401
Mangaung LM	Leon Kritzinger	Centlec, Brandhof, 9324	051 409-2241	051 409-2366
Matjhabeng Municipality	France Mtshweni	P O Box 708, Welkom, 9471	057 391-3116	057 391-3450
Matzikama LC	Deon Engelbrecht	P O Box 98, Vredendal, 8160	027 201-3314	027 213-5557
Mbombela Local Municipality	Boiling Twala	P O Box 45, Nelspruit, 1208	013 759-2230	013 752-7168
Merafong City Council	Ezra Shange	P O Box 3, Carletonville, 2499	018 788-9651	018 788-9659
Metsimaholo Municipality	Hennie van Wyk	P O Box 60, Sasolburg, 1947	016 973 2191	016 976-0209
Midvaal Local Municipality	Chief Engineer	P O Box 9, Meyerton, 1960	016 360-7553	086 619-3332
Mkhondo Municipality	Alfred Mambane	P O Box 23, Piet Retief, 2380	017 826-2211	086 675-8099
Modimolle Local Municipality	P Radebe	Private Bag X1008, Modimolle, 0510	014 718-2032	014 717-4077
Mogalakwena LC	Johannes Fourie	P O Box 34, Mokopane, 0600	015 491-9601	015 491-9687
Mogale City Local Municipality	Frikkie Erasmus	P O Box 94, Krugersdorp, 1740	011 951-2440	011 665-2438
Moqhaka Municipality	Louis Greef	P O Box 302, Kroonstad, 9499	056 216-9283	056 216-9284
Mossel Bay LC	William Olivier	P O Box 25, Mosselbay, 6500	044 606-5081	044 691-1903

AMEU Engineering Members

Organisation	Name	Address	Phone	Fax
Msunduzi Municipality	Eveon Nomganga	Havelock Road, Pietermaritzburg, 3201	033 392-3000	033 392-5150
Municipal Council of Mbabane	Artwell Dludlu	P O Box 13, Swaziland, Sz 748	+268 24097049	+268 608 2611
Musina Local Municipality	Simon Phiri	Private Bag X611, Musina, 0900	015 534-6181	086 518-4297
Nama Khoi Municipality	Pieter Opperman	P O Box 17, Springbok, 8240	027 718-8161	086 758-7799
Nampower	Braam Vermeulen	P O Box 2864, Windhoek, Namibia	+264 12 052961	+264 61 232805
Nelson Mandela Bay Municipality	Mvuleni Bukula	P O Box 116, Port Elizabeth, 6020	041 505-4417	041 505-4478
Newcastle Municipality	Phumlani Xulu	Private Bag X6621, Newcastle, 2940	034 312-1296	034 312-9697
Oudtshoorn Municipality	Corrie Greef	P O Box 255, Oudtshoorn, 6620	044 203-3159	044 203-3158
Overstrand Municipality	Deon Louw	P O Box 20, Hermanus, 7200	028 384-8311	028 384-8314
Phokwane Municipality	Martinus Blaauw	Private Bag X3, Hartswater, 8570	053 474-9752	053 474-1768
Pixley Ka Seme Local Municipality	Eugene van Dyk	Private Bag X9011, Volksrust, 2470	017 734-6100	086 561-8756
Polokwane Municipality	Pine Pienaar	P O Box 111, Polokwane, 0699	015 290 2270	015 290-2249
Renewable Energy & Energy Efficiency Institute	Kudakwashe Ndhlukula	Private Bag 13388, Windhoek, Namibia	+264 61 207 205	+264 61 207 205
Rustenburg Municipality	Dolf du Preez	P O Box 16, Rustenburg, 0300	014 590-3170	014 590-3430
Saldanha Bay LC	Louis Scheepers	Private Bag X12 , Vredenburg, 7395	022 701-7066	022 713-4472
Setsoto Local Municipality	Arthur John Addinall	P O Box 116, Ficksburg, 9730	051 933-9302	058 481-2043
Sol Plaatje Municipality	B Dhluwayo	Ed Infrastructure & Services, Kimberley, 8300	053 830-6646	053 831-5955
Stellenbosch Municipality	Joseph Hames	P O Box 17, Stellenbosch, 7599	021 808-8331	021 698-1431
Steve Tshwete Municipality	Raymond Grunig	P O Box 14, Middelburg, 1050	013 249-7221	013 249-7065
Swartland LC	Roelof du Toit	Private Bag X52, Malmesbury, 7300	022 487-9400	022 487-9440
Thabazimbi Local Municipality	Gopolang Booysen	P O Box 90, Thabazimbi, 362	014 777-1525	014 777-1066
Theewaterskloof Municipality	Francois du Toit	P O Box 24, Caledon, 7230	028 214-1628	028 212-2199
Tlokwe Local Council	J van den Berg	P O Box 113, Potchefstroom, 2530	018 299-5401	018 299-5446
Umjindi Municipality	AWJ Landsberg	P O Box 33 , Barberton, 1300	013 712-8805	013 712-5120
uMlalazi Municipality	Jaap le Grange	P O Box 37, Eshowe, 3815	035 473-3410	035 474-2250
Umtshezi Municipality	Cyril Moodley	P O Box 15, Estcourt, 3360	036 342-7800	086 529-8036
Umvoti LC	Gerhard Bolzer	P O Box 71, Greytown, 3250	033 413-9119	033 413-9183
Victor Khanye Municipality	Leslie Niewenhuizen	P O Box 6, Delmas, 2210	013 665-5754	086 576-5137
Witzenberg Municipality	Brian van der Watt	P O Box 44, Ceres, 6835	023 316-1854	023 316-1877

AMEU Past Presidents

Date	Name	City	Date	Name	City	Date	Name	City
1915-1917	JH Dobson	Johannesburg	1947-1948	C Kinsman	Durban	1973-1975	JC Waddy	Pietermaritzburg
1917-1918	J Roberts	Durban	1948-1949	A Forden	East London	1975-1977	E de C Pretorius	Potchefstroom
1919-1920	B Sankey	Port Elizabeth	1949-1950	DA Bradley	Port Elizabeth	1977-1979	KG Robson	East London
1920-1922	TC Walley Dodd	Pretoria	1950-1951	CR Halle	Pietermaritzburg	1979-1981	PJ Botes	Roodepoort
1922-1924	GH Swingler	Cape Town	1951-1952	JC Downey	Springs	1981-1983	DH Fraser	Durban
1924-1926	J Roberts	Durban	1952-1953	AR Sibson	Bulawayo	1983-1985	W Barnard	Johannesburg
1926-1927	B Sankey	Johannesburg	1953-1954	JC Fraser	Johannesburg	1985-1987	JA Loubser	Benoni
1927-1929	J Mordy Lambe	East London	1954-1955	GJ Muller	Bloemfontein	1987-1989	AHL Fortman	Boksburg
1929-1931	R Macauley	Bloemfontein	1955-1956	DJ Hugo	Pretoria	1989-1991	FLU Daniel	Cape Town
1931-1933	LL Horrel	Pretoria	1956-1957	JE Mitchell	Bulawayo	1991-1993	CE Adams	Port Elizabeth
1933-1934	LF Bickell	Port Elizabeth	1957-1958	JL van der Walt	Krugersdorp	1993-1995	HR Whithead	Durban
1934-1935	AR Metelerkamp	Bulawayo	1958-1959	CG Downie	Cape Town	1995-1997	JG Malan	Kempton Park
1935-1936	GG Ewer	Pietermaritzburg	1959-1960	R Wcane	Johannesburg	1997-1999	HD Beck	East London
1936-1937	A Rodwell	Johannesburg	1960-1961	RMO Simpson	Durban	1999-2001	AJ van der Merwe	Bloemfontein
1937-1938	JH Gyles	Durban	1961-1962	C Lombard	Germiston	2001-2003	J Ehrich	Pretoria
1938-1939	HA Eastman	Cape Town	1962-1963	PA Giles	East London	2003-2004	PE Fowles	Pietermaritzburg
1940-1944	IJ Nicholas	Umtata	1963-1964	JC Downey	Springs	2004-2006	D Potgieter	Polokwane
1944-1945	A Rodwell	Durban	1964-1965	RW Barton	Welkom	2006-2007	V Padayachee	Johannesburg
1945	JS Clinton	Harare	1965-1967	D Murray-Nobbs	Port Elizabeth	2007-2008	S Maphumulo	Durban
1945-1946	JW Phillips	Harare	1967-1969	GC Theron	Vanderbijlpark	2008-2010	S Gourrah	Buffalo City
1946-1947	GJ Muller	Bloemfontein	1969-1971	HT Turner	Umtali	2010-2012	M Rhode	Drakenstein
			1971-1973	JK Von Ahlften	East London			

AMEU Affiliate Members

Organisation	Name	Address	E-mail	Phone
3M South Africa	Shawn Ramsunkar	146A Kelvin Drive, Woodmead, 2191	sramsunkar@mmm.com	011 806-2033
ABB South Africa	Moses Lekoro	Private Bag X10004, Edenvale, 1610	sales@za.abb.com	010 202-5381
Aberdare Cables	Siphithi Sibeko	P O Box 1679, Edenvale, 1610	ssibeko@aberdare.co.za	011 396-8240
ACTOM Electrical Products	Elliott Moswane	P O Box 678, Germiston, 1401	elliot.moswane@actom.co.za	011 878-3389
ACTOM Protection and Control	Kevin Govender	572 Amber Valley, Howick, 3290	kevin.govender@actom.co.za	011 820-5127
ACTOM	John Williams	P O Box 13024, Knights, 1413	john.williams@actom.co.za	011 820-5239
Acumen Software	Kennedy Mogotsi	P O Box 1723, Lonehill, 2063	kennedy.mogotsi@acumensoft.net	011 467-8528
ADC Energy	Tonia Steyn	60 Electron Avenue, Isando, 1601	tanias@adcenergy.co.za	011 397-8168
Afritek	Neelesh Pema	P O Box 980, Olifantsfontein, 1665	neelesh.pema@afriteksa.co.za	011 316-7512
AJ Charnaud & Co.	Lizanne Scholtz	P O Box 4332, Honeydew, 2040	marketing@charnaud.co.za	011 794-6040
Alectrix	Richard Still	P O Box 26120, Hout Bay, 7872	richard@alectrix.co.za	021 790-1665
Altech Alcom Matomo	Cedric Rigney	P O Box 5574, Rivonia, 2128	crigney@alcom.co.za	011 235-7678
ARB Electrical Wholesalers	Charle Leibbrandt	P O Box 26426, Isipingo Beach, 4115	charlel@arb.co.za	031 910-0115
Arcus Gibb	Paul Fitzsimons	P O Box 2700, Rivonia, 2128	pfitzsimons@gibb.co.za	011 519-4600
Aurecon SA	Dr Baholo Baholo	P O Box 905, Pretoria, 0001	valley.nkonde@aurecongroup.com	012 427-2334
Ballenden & Robb SA	Willy Bruggeman	P O Box 955, Port Elizabeth, 6000	projects@ballenrobb.co.za	021 851-1455
BDE Consulting Engineers	Danie De Vries	P O Box 1862, George, 6530	devries@bdeconsult.co.za	044 801-9700
Beka	Gordon Arons	P O Box 120, Olifantsfontein, 1665	vermeulene@beka.co.za	011 238-0002
Bigen Africa Services	Anton George Booyzen	P O Box 5339, Rivonia, 2128	nomsa.modise@bigenafrica.com	011 802-0560
Bodacious Energy	Madeleen Botha	P O Box 1701, Gallor Manor, 1685	madeleen@bodacious.co.za	011 258-8920
Brighten UP IT	Shane van Jaarsveldt	P O Box 64, Johannesburg, 2068	shane@brightenup.co.za	011 469-4750
BVI Consulting	Arnold Markram	P O Box 1155, Upington, 8800	arnoldm@bvinc.co.za	054 337-6600
Cable Guard SA	Marc Goldring	P O Box 1822, Mulbarton, 2059	marc@cableguard.co.za	083 658-0291
Carifro Consulting Engineers	David Frost	P O Box 35091, Port Elizabeth, 6055	davef@carifro.com	041 392-9896
CBI Electric: African Cables	Kobus Coetzer	P O Box 172, Vereeniging, 1930	marieta.pretorius@cbi-electric.com	016 430-6000
Circuit Breaker Industries Limited	Nancy Austin	Private Bag 2016, Johannesburg, 1600	rbekker@cbi-electric.com	011 928-2022
Clinkscales Maughan-Brown	Pierre Conradie	P O Box 2551, George, 6530	pconradie@cmbgeorge.co.za	044 874-1511
Conlog	Vikki Vink	P O Box 2332, Durban, 4000	info@conlog.co.za	031 268-1375
Consolidated Power Projects	Hanlie Farmer	Private Bag X 42, Midrand, 1685	hanlie.farmer@conco.co.za	011 805-4281
Contour Technology	Accounts Dept	P O Box 37730, Overport, 4067	admin@contour.co.za	031 266-9746
CT LAB	Willie van Wyk	P O Box 897, Stellenbosch, 7599	info@ctlab.co.za	021 880-9915
CU AL Engineering	Andrew Walsh	P O Box 202079, Durban North, 4016	andrew@cual.co.za	031 569-1242
Cullin Africa cc	Krish Chetty	P O Box 78, Noordwyk, 1687	info@cullin.co.za	011 848-1400
De Villiers & Moore	Louise Basson	P O Box 472, Durbanville, 7551	louise@devmoore.co.za	021 976-3087
DFR Engineers	Deon Roodt	P O Box 911716, Rosslyn, 0200	reception@dfreng.co.za	012 546-7574
Dihlase Consulting Engineers	Benita Pienaar	Postnet Suite 258, Brandhof, 9324	stephenn@dihlase.co.za	051 447-1636
Dipro	Ivica Debeljkovic	P O Box 131, Hurlingham View, 2070	ivica@dipro.co.za	011 787-3835
Doble Engineering Africa	Luwendran Moodley	P O Box 1150, Durban, 3631	lmoodley@doble.com	031 266-2920
DSG CANUSA	Paul Sheridan	DSG Canusa,Bergstrand House, England, Pl6 7SG	psheridan@dsgcanusa.com	+44 1752 209880
Eaton Electrical South Africa	Mark Strydom	Private Bag X019, Wadeville, 1422	markstrydom@eaton.com	011 827-9124
Eberhardt-Martin	Gerard Connolly	P O Box 58365, Delarey, 2114	gerard@ebm.co.za	011 288-0000
ECA (SA)	Cecil Lancaster	P O Box 12011, Hatfield, 0028	cecil@ecasa.co.za	012 342-3358
Edison Jehamo Power	Shirene Rogers	P O Box 893, Isando, 1600	srogers@ejp.co.za	011 578-1700
EE Publishers	Chris Yelland	P O Box 458, Muldersdrift, 1747	mike.rycroft@ee.co.za	011 543-7000
EHT Cables	Martin Burls	15 Walloon Road, Constantia, 7806	eht@iafrica.com	021 705-1568
Electro Inductive Industries	Michael Jason	P O Box 1454, Brackenfell, 7561	mike@electroi.co.za	021 980-9600
e-Lek Engineering	Leon Knoll	P O Box 70577, Pretoria, 0041	leon@elek.co.za	012 349-2220
Element Consulting Engineers	Christo Botha	P O Box 1142, Durbanville, 7551	cbotha@eceng.co.za	021 975-1718
Elex Khanyisa	Chris Joubert	Unit 7, Killarney Gardens, 7441	cjoubert@elexkhanyisa.com	021 556-2460
Elexpert	Hendrik Barnard	P O Box 4069, Randburg, 2125	hbbarnar@mweb.co.za	011 787-7566
Elster Kent Metering	Simon Dart	P O Box 201, Auckland Park, 2006	elizabeth.kuhn@za.elster.com	011 470-4965
Energy Audit Lighting	Llewellyn Curlewis	P O Box 412891, Craighall, 2024	llewellyn@energyaudit.co.za	011 789-6913
Enermatics Energy	Rajendran Naidoo	P O Box 323, Pretoria, 0063	raj.naidoo@enermatics.co.za	012 486-8624
ERIC	James Baker	P O Box 912479, Pretoria, 0127	bakerjc@telkomsa.net	012 753-8082
Escotek	Judith Dorland	Posnet Suite 21, Monument Park, 0105	marketing@escotek.co.za	012 347-7034
Eya Bantu Professional Services	Mike Brown	8 Scherwitz Street, East London, 5201	mike@eya-bantu.co.za	043 726-2726
Farad	Peter Gerber	P O Box 31220, Braamfontein, 2017	farad@farad.co.za	011 726-4090
First National Battery Industrial	Desegan Govindsamy	P O Box 5015, Benoni, 1500	desegan@battery.co.za	031 502-4227
Genlux Lighting	Sello Tsoai	P O Box 1183, Germiston, 1400	sello@genlux.co.za	011 825-3144
George Stott & Co	Jonas Maentetje	P O Box 43011, Industria, 2042	jonasm@geostott.co.za	011 474-9150
Greenbro	Pierre Brink	9 Teksteel Road, Parrow Industrial, 7505	pierre.brink@greenbro.co.za	021 933-9560
Gubela Trading	Zanele Njova	P O Box 389, New Germany, 3610	gubela.trading@gmail.com	031 705-9529

AMEU Affiliate Members

Organisation	Name	Address	E-mail	Phone
H.B Osman T/a Universal Eco Lighting	Hajira-Bibi Osman	P O Box 26452, Isipingo Beach, 4115	prebashni@usel.co.za	031 584-8007
H.V. Test	Madelene Pienaar	P O Box 651287, Benmore, 2010	madelene@hvtest.co.za	011 782-1010
Hamsa Consulting Engineers	Vinodh Munessar	P O Box 1943, Umhlanga Rocks, 4320	vinodh@hamsaeng.co.za	031 572-5723
Hi Tech Transformer Maintenance	Zakhele Ntombela	P O Box 5094, Meyersdal, 1447	info@hitechco.co.za	011 626-2884
I.B Mcintyre & Co - Master Lock	Harry Folly	P O Box 342, Maitland, 7404	harryf@mackiediy.co.za	011 392-4154
ID2	Dagmar Noome	P O Box 72614, Pretoria, 0040	dagmar.noome@id2metering.com	012 470-2200
Idube Electrical	Keith Erwin	P O Box 15474, Lambton, 1414	keith@idube.net	011 397-8281
Igoda Projects	Frederick Rolf Niemand	P O Box 1530, Westville, 3630	rolf@igoda.co.za	031 536-7300
Ilanga Lighting Distribution	Amar Singh	P O Box 27129, Jeppestown, 2043	amar@magnitech.co.za	011 618-2720
Impact Energy	Wayne Bromfield	29 Hopson Avenue, Durban, 4001	wayne@impactenergy.co.za	031 201-7191
Imvuselelo Consultants	Francois van Wyk	P O Box 698, Westville, 3630	francois@jcf-eng.com	031 266-2707
Infraset (A Business Unit of Aveng Africa)	Sizwe Mkhize	P O Box 365, Brakpan, 1540	smkhize@infraset.com	011 813-2340
Instrument Transformer Technologies	Johan du Preez	P O Box 2150, Primrose , 1416	johan@ittza.co.za	011 822-8022
Integrity Control Systems	Claudia Coetzer	Postnet Suite 126, Bedfordview, 2008	claudia@integritycontrol.co.za	011 397-2508
IPES - Utility Management Services	Kiewiet Adendorff	P O Box 11000 , Centurion, 0046	kiewiet@utility.co.za	012 665-4509
Isizwe Transmissions & Transformers	Derick Ramnarian	P O Box 764, Durban, 4000	derick@s-team.co.za	031 332-1440
Iso-Tech Systems	Ben Wagner	P O Box 13442, Vorna Valley, 1686	quality@iso-tech.co.za	011 466-3701
Itron	Ivar Kilian	P O Box 4059, Cape Town, 7536	ivar.kilian@itron.com	021 928-1700
Izembe Technologies	Sipho Mthembu	P O Box 10514, Centurion, 0046	sipho@izembe.com	012 667-4216
Jas Engineering	Lawrence Chetty	P O Box 17711, Norkem Park, 1631	jas@absamail.co.za	011 393-4674
JoCastro	Michelle da Santos	P O Box 1548, Dassenberg, 7350	michelle@jocastro.co.za	021 577-1602
Karebo Systems	Ravi Govender	P O Box 7895, Halfway House, 1685	sahejna.jadoo@karebo.co.za	011 234-0660
KBK Power Solutions	Fred Peters	P O Box 133, Cato Ridge, 3680	fred@kbkps.co.za	031 782-1329
KoCos Measurement & Control	Hein Erwin	P O Box 3585, Durbanville, 7551	herwin@kocos.co.za	021 982-0016
Landis + Gyr	Nangamso Ngxono	P O Box 4052, Pretoria, 0158	nangamso.ngxono@landisgyr.com	012 645-3152
LeBlanc Jasco Lighting Structures	Jacques Tait	P O Box 1592, Nigel, 1490	jacques@lightingstructures.co.za	087 310-1000
Lebohang Project Management	Rudolph Evert	P O Box 650234, Benmore, 2010	rudolph.evert@lebohang.com	011 784-0141
Letcha Engineering Solutions	Khabane Chabedi	P O Box 145631, Bracken Gardens, 1452	khabane@letcha.co.za	087 808-8768
LH Marthinusen (a division of ACTOM)	Johan van Wyk	P O Box 27440, Benrose, 2011	johanv@lhm.co.za	011 615-6722
Light-Be Lighting	Willie Garbers	P O Box 3112, Witbeeck, 1729	willie.garbers@light-be.co.za	011 762-6874
Lightwatt	Ray Evans	P O Box 2147, Cresta, 2118	ray@lightwatt.co.za	074 117-9379
Live Line Technology	Kevin Risi	P O Box 2502, Klerksdorp, 2570	kevin@liveline.co.za	018 468-3344
Lucy Electric South Africa	Rick St. John	Postnet Suite #1, Bryanston, 2021	rick.stjohn@lucyswitchgear.com	011 513-3415
Lyon & Vennote	Martiens Lyon	P O Box 3925, Vanderbijlpark, 1900	mlyon@lyon.co.za	016 981-6270
Malaysian Switchgear Distributors	Alan Carter	P O Box 38302, Booysens, 2016	reception@malaysianswitchgear.co.za	011 298-1800
Mandlakazi Electrical Technologies	Lindiwe Sibande	P O Box 1836, Nelspruit, 1200	lindi@met.co.za	013 755-2257
Manelec Services	Hendrin Germishuys	P O Box 955, Port Elizabeth, 6000	planning@manelec.co.za	041 581-2262
MARTEC	Mario Kuisis	P O Box 3227, Randburg, 2125	mario@martec.co.za	011 326-2708
McWade Productions	Marc Hindle	P O Box 142, Olifantsfontein, 1665	march@mcwade.co.za	011 316-2262
Medupe Distributors	Lemao Mataung	P O Box 966, Johannesburg, 1600	lemao@medupedistributors.co.za	011 397-2913
Megatron Federal (Div of Ellies)	Leon Blumberg	P O Box 2391, Kempton Park, 1620	gerald@megatronfederal.com	011 976-3003
Megger Limited	Marius Pitzer	P O Box 22300, Glen Ashley, 4022	marius.pitzer@megger.com	031 564-6578
Milsoft Utility Solutions	Brian Carr	P O Box 5726, Abilene, Tx 79608	brian.carr@milsoft.com	+13 252 201 4219
Molemole Municipality	Phuti Ntjana	P O Box 341, Molemole, 0790	ntjanapi@webmail.co.za	015 501-0243
Motla Consulting Engineers	JL Mocke	P O Box 10914, Centurion, 0046	info@motla.co.za	012 663-1328
Musco Lighting	Derek Field	P O Box 201165, Durban North, 4016	derek.field@musco.com	086 1000-373
National Cables	Annemarie Booyens	P O Box 136106, Alberton North, 1456	luzaan_lennox@pdic.com	011 824-4747
NETGroup South Africa	Pieter Conradie	Postnet Suite #444, Pretoria, 0102	pjd.conradie@netgroup.co.za	011 475-0623
Nexans Trade	Robert Harrington	P O Box 14142, Farrarmere, 1518	nexans.africa@intekom.co.za	011 421-7055
Nkwazi Consulting Engineers	Dwayne Baker	P O Box 50398, Richards Bay, 3900	reg@richemp.org.za	035 786-1431
Nordland	Cyril Nunns	P O Box 522, Muldersdrift, 1747	cyril@nordland.co.za	011 662-4300
Ntamo Technologies	Quentin Louw	23 Chasewater Street, Alberton, 1449	admin@ntamotechnologies.co.za	086 126-8266
Nynas South Africa	Alistair Meyer	Suite 550, Weltevreden Park, 1715	alistair.meyer@nynas.com	010 590-1052
Optron Geomatics	Russel Meyer	P O Box 7911, Centurion, 0046	rmeyer@optron.com	012 683-4500
Palace Engineering	Mbuso Dlamini	Postnet Suite 405, Sandton, 2146	busdevelop@palacegroup.co.za	011 783-5698
Parsons Brinckerhoff Africa	Leon Fourie	P O Box 41927, Craighall, 2024	fouriel@pbworld.com	011 514-7200
Pat Naidoo Consulting Engineers Inc RSA	Pat Naidoo	P O Box 2103, Westville, 3630	pat@patnaidoo.co.za	031 409-3130
Patch Industrial Supplies & Consulting	Michael Tyszowiecki	P O Box 5123, Tyger Valley, 7536	patch@worldonline.co.za	021 981-2769

AMEU Affiliate Members

Organisation	Name	Address	E-mail	Phone
PEC Metering	Frikkie Nel	P O Box 3157, Durbanville, 7551	frikkien@pecgroup.co.za	021 948-0225
PennWell Corporation	Lee Catonia	The Water Tower, Waltham Abbey, EN9 1BN	leec@pennwell.com	+447 83 390 561
Phambili Merz	Richard Frantz	Mott Macdonald, Johannesburg, 2128	richard.frantz@mottmac.com	087 310-5100
Philips Lighting South Africa	Lorato Maphiri	P O Box 58088, Newville, 2114	lorato.maphiri@philips.com	011 471-5074
Pienaar & Erwee Engineers	Johann Erwee	P O Box 1831, Brooklyn Square, 0075	mail@erwee.co.za	012 998-5219
Plantech Associates	Hein Schuld	P O Box 146, Persequor Park, 0020	plantech@plantech.co.za	012 349-2253
Poly Box	Peter Willers	P O Box 51578, Waterfront, 8002	peter@polybox.co.za	021 931-9233
Power Process Systems	Ben Roode	P O Box 4172, Southgate, 2082	pps.sales@iafrica.com	011 494-3550
Power-C Metering Africa	Clifford Ntsudisane	P O Box 653592, Benmore, 2010	clifford@powercommetering.co.za	011 523-3000
Powertech IST	Ilze Smith	Private Bag X95355, Waterkloof, 0145	ilzes@ist.co.za	012 426-7484
Powertech Management Services	Jaco Roetz	P O Box 1090, Johannesburg, 2152	jroetz@tis-sa.com	011 706-7184
Powertech Transformers	Jacqui Burn	P O Box 691, Pretoria, 0001	jacqueline.burn@pttransformers.co.za	012 318-9802
Pragma Africa	Alan Tait	P O Box 3971, Tygervalley, 7360	alan.tait@pragmaworld.net	011 318-0641
Preformed Line Products (SA)	Billy Oosthuyzen	P O Box 4015, Pietermaritzburg, 3210	sales@preformedsa.co.za	033 397-5800
PricewaterhouseCoopers	Jan Gey van Pittius	Private Bag X 36, Sunninghill, 2157	jan.gey.van.pittius@za.pwc.com	011 797-4134
Progressive Energy	Greg Schaufelbuhl	Suite 72, Cape Town, 7872	energy2energy@gmail.com	021 511-5580
Protective Structures	Connie Brooks	P O Box 1701, Rivonia, 2128	connie@mweb.co.za	011 917-3570
Quanta Services Africa	Fred Visser	P O Box 18598, Sunward Park, 1470	fvisser@quantaservices.colm	011 392-4761
Quiktrak Networks Africa	Clinton Lemmer	P O Box 1554, Stellenbosch, 7559	clint@quiktrak.co.za	011 253-3140
Reinhausen South Africa	Danie Venter	P O Box 1395, Southdale, 2135	c.mckenzie@za.reinhausen.com	011 835-2077
Reticulation and General Supplies	Louis Bezuidenhout	P O Box 1402, Sanlamhof, 7532	wolfgang@rgs-sa.co.za	021 982-7940
Revive Electrical Transformers	Dharmalingum Padayachee	P O Box 83334, Johannesburg, 2136	revive@global.co.za	011 613-1508
ROCLA	Kevin West	P O Box 92, Roodepoort, 1725	kevin.west@murrob.com	011 670-7600
Rotek Engineering	Gift Dladla	P O Box 40099, Cleveland, 2022	gift.dladla@eskom.co.za	011 629-4435
RPS Ilangabi	R Masuku	P O Box 1670, Westville, 3630	regis@rpsilangabi.co.za	031 266-9505
RPS Switchgear SA	Ron Niemack	P O Box 7157, Boonaero Park, 1622	ron@rpsswitchgearsa.co.za	011 914-2395
Rural Maintenance	Pieter du Toit	P O Box 73130, Lynnwood Ridge, 0040	accounts@remig.co.za	021 883-8252
SABS Commercial	Lucas Munyai	Private Bag X191, Pretoria, 0001	shweta.biddassee@sabs.co.za	012 428-6934
SABS Standards Division	Willa Breed	Private Bag X 191, Pretoria, 0001	willa.breed@sabs.co.za	012 428-6613
Schneider Electric	Isaac Kruger	Private Bag X139, Johannesburg, 1685	isaac.kruger@schneider-electric.com	011 254-6400
Schweitzer Engineering Lab	Deon Joubert	P O Box 68256, Highveld, 0169	deonjo@selinc.com	012 664-5930
Sectional Poles	Morne van Zyl	P O Box 17028, Groenkloof, 0027	jaco@sectionalpoles.co.za	012 348-8660
Solethu	Neil Morris	P O Box 109, Eppindust, 1685	neilm@solethuenergy.co.za	021 530-8060
South African National Energy Development Institute	Dr Minesh Bipath	P O Box 786141, Sandton, 7405	minnesh.bipath@sanedi.org.za	010 201-4751
Southern Electricity Company	Abraham Kukuri	P O Box 1445, Namibia, 2146	abraham.kukuri@remig.co.za	+26 48 112 9313
Specialist System Engineering	Gert Bezuidenhout	P O Box 7170, Centurion, 0046	gbez@sse.co.za	012 663-4331
Spectrum Communications	Kevin Clack	P O Box 36900, Chempet, 0046	kevin.clack@spectrumcom.co.za	021 551-5800
Spintelligent	Andrew Dooley	P O Box 321, Steenberg, 7442	brigitte.hart@spintelligent.com	021 700-3500
SSI Engineers and Environmental Consultants	Buren-Schele	P O Box 867, Johannesburg, 7947	erict@ssi.co.za	012 367-5891
Static Power (a div of Actom)	Nichola Fort	P O Box 13424, Witfield, 2052	sales@static.co.za	011 397-5316
Stefanutti Stocks Power	Emmanuel Njapha	111 Mypark Drive, Parlock, 1467	emmanuel.njapha@stefstocks.com	011 254-5700
Stone-Stamcor	Mark Talbot	P O Box 1352, Edenvale, 4037	markt@stonestamcor.co.za	011 452-1415
Strike Techenologies	Brent Kinloch	P O Box 1810, Halfway House, 1610	brentk@strike.co.za	011 315-0815
Sure Engineering	Neil Jeffrey	P O Box 63, Steenberg,Cape Town, 1685	nj@suretech.co.za	021 701-8529
Surge Technology	Premesh Narismulu	P O Box 3109, Randburg, 7947	premeshn@mweb.co.za	011 792-1303
Switchboard Manufacturers	Ricky Rangiah	P O Box 40086, Red Hill, 2125	rickyr@switchboard.co.za	031 508-1520
Syntell	Cherelle Esau	P O Box 30298, Tokai, 4071	cherelle@syntell.co.za	021 710-2045
Tank Industries a Division of ATC	Adriaan Theron	P O Box 9, Steenberg, 7966	Adriaan.Theron@tank.co.za	021 789-2712
Telecom 180	Delio Senatore	P O Box 11106, Pretoria, 7947	delios@ansystelecom.co.za	012 360-0400
Thusani Brokers	Bernard Mberewere	Suite no 2 , La Lucia, 0181	bernard@thusanibrokers.co.za	031 566-2897
Touchwork	Rudi Leitner	P O Box 30875, Cape Town, 7441	rudi.leitner@touchwork.com	021 702-4135
Tridonic SA	Trevor Milne	P O Box 30542, Jetpark, 7966	trevor@tridonic.co.za	021 707-5340
Trimble	Mark Osborne	National Software Centre, Cork, 1469	mark_osborne@trimble.com	+35 32 123 0932
Tulisa Cables	David Macfadyen	P O Box 83704, South Hills, 2197	davidm@tulisacables.co.za	011 907-6385
Turnkey Metering Solutions	Navi Naidoo	84 Columbine Place, Durban North, 2136	navi@turnkeymetering.com	031 569-4085
Ulungeni Consulting	Jan Jordaan	P O Box 1521, Empangeni, 4051	ulungeni@iafrica.com	035 792-1026
Utillabs	Paroshen Naidoo	20 Thornhill Office Park, Vorna Valley, 3880	paroshen.naidoo@utillabs.com	011 805-0094
VAMP Solutions	Rodney Bristow	P O Box 11798, Selcourt, 1685	rbristow@vamp.co.za	011 818-2190
Vela VKE Consulting Engineers	Steyn de Lange	P O Box 72927, Lynnwood Ridge, 1567	delanges@velavke.co.za	012 481-3800
Verotest	Veronica Merry	P O Box 50559, Randjiesfontein, 0040	veronica@verotest.co.za	011 805-8322

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Organisation	Name	Address	E-mail	Phone
Vetasi	Bouke Spoelstra	P O Box 39178, Pretoria, 1683	bouke.spoelstra@vetasi.com	012 348-4617
Voltano	Marius Schwartz	Postnet Suite 293, Lyttelton, 0043	marius@voltano.com	012 940-9272
Voltex t/a Voltex Cape	Corry Marinus	P O Box 291, Maitland, 0140	wcregional@voltex.co.za	021 530-3460
WDI Consultants	Accounts Payable	P O Box 3639, Randgate, 7404	louis.steynwdi@gmail.com	082 895-4899
Woodbeam	BV Magee	P O Box 526, Modderfontein, 1763	info@woodbeam.co.za	0861 966-323
WorleyParsons RSA	Come Smith	P O Box 36155, Bellville, 1645	come.smith@worleyparsons.com	012 452-6300
Y Wecan Environmental Trading	Norman Maharaj	B34 Platinum Junction, Cape Town, 7441	norman@nanolandsa.com	021 552-9855
Zest WEG Group	Jamie Wilson	Private Bag X10011, Sandton, 2146	jamiew@zest.co.za	011 723-6000

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1963	CG Downie
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1965	G Muller
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1969	W Beesley
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1971	DJ Hugo
	ACT Frantz
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Period	Name
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1975	Clr HG Kipling
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	JG Wannenberg
1977	Dr. RL Straszacker
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	GC Theron
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	Dr. RB Anderson
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1985	AA Weich
	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
1993	FLL Daniel
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Period	Name
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1997	JD Algera
	HR Whitehead
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1999	JG Malan
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2010	O Bothma
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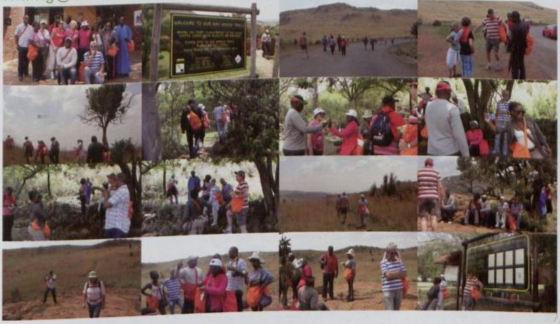

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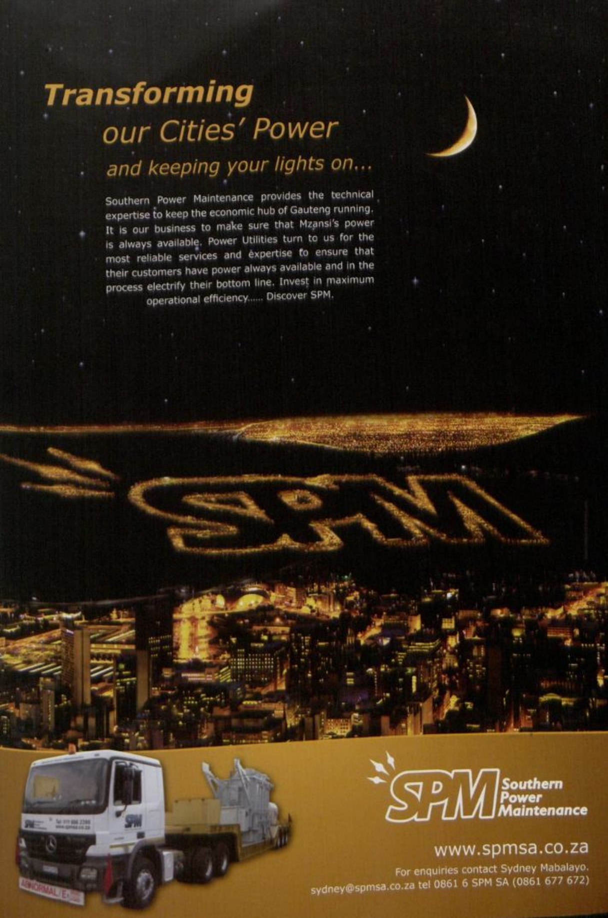
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