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ESI AFRICA

Changing the rules once a competitive bid is concluded is a sure-fire route to destroying investor confidence and sabotaging South Africa's economic interests, writes Brenda Martin, Chairperson of the South African Renewable Energy Council (SAREC).

The future of South Africa's RE hangs in the balance

For the past year, the steady growth of investment in renewable power has been stalled by an extended impasse between Eskom and the RE industry. At the time of writing, Eskom has refused to sign PPAs arising from the fourth round of government's much-lauded renewables programme.

Government support for the programme is clear – The Presidency, National Treasury, Ministry of Energy, IPP Office – all have repeatedly indicated their support both for the programme as a whole, and for the conclusion of outstanding PPAs in line with procurement. Nevertheless, Eskom continues to insist that it will only conclude these on condition that it is able to re-negotiate tariffs.

SAREC has taken legal opinion from senior counsel as to whether Eskom is entitled to delay or prevent the signature of PPAs. Counsel has concluded that Eskom has no such prerogative. Ministerial determinations are binding on Eskom and the utility has no discretion to impose further conditions on preferred bidders. Eskom certainly has no legal authority to negotiate tariffs with already selected bidders.

This is a crucial year for South Africa's long-term energy future in general, and the renewables sector in particular. Both the Integrated Energy Plan and the Integrated Resource Plan are currently out for public comment. Beyond energy planning, public support for good governance is higher than ever.

The country's REIPPP Programme was born out of government's vision for an expansion of South Africa's energy mix to include independent power with a range of clear developmental imperatives.

As procurement rounds have been completed and implementation has proceeded, ample evidence of the industry's contribution to the economy has emerged. From a standing start renewables accounted for 84% of all foreign direct investment in 2014 and leapt to the top of the African league table with one of the most admired programmes in the world. While 64 preferred bidders proceeded with implementation, in 2016, foreign direct investment dwindled to a fraction of the 2014 sum.

Approximately ZAR58 billion ($4.4 billion) and 13,000 jobs have effectively been placed on hold, while further duly procured power purchases have not been concluded by the national utility.

If it is up to the national utility, the future of the South African renewables industry will continue to hang in the balance. Unlike monopoly utilities however, governments are entrusted with prioritising the national interest – in the short and long term. In this crucial year for energy planning, South African citizens will have ample opportunity to influence future investment opportunities. The future of South Africa's renewable energy industry is thus firmly in the hands of its government and its citizens. **ESI**

Planning, developing and executing major investment projects, particularly those using the latest technology, presents companies with as many challenges as it does opportunities, writes Phil Dingle, marketing director at Lucy Electric.

Adding value through effective project management

Across the world, demand for electricity is intensifying and distribution companies are facing growing challenges to establish a stable, reliable and high performance distribution network. Africa is no exception with both business and domestic demand for electricity rising rapidly as a result of connection projects, population growth, urbanisation and sustained economic development.

The electrification challenge facing Africa is huge, placing increasing pressure on already overstretched networks, with many utilities looking to extend and upgrade infrastructure. Alongside this there is growing interest in developing renewable generation sources as organisations recognise that these schemes can play a major part in addressing the generation shortfall in Africa.

So how do utilities respond to these complex challenges? For investment strategies to be successful, companies need to make sure development projects effectively meet both today's and tomorrow's needs. Network automation and smart grid projects are being seen as the way forward to help companies manage increasingly complex networks. But planning, developing and executing major investment projects, particularly those using the latest technology, presents companies with as many challenges as it does opportunities.

A trusted and reliable partner

For successful project delivery, companies need a clear view of future needs and a project partner they can trust to deliver projects from end-to-end reliably, economically and sustainably.

This is where partnering with an organisation such as Lucy Electric can help. The company's experts work at the cutting-edge of distribution projects and can help organisations scope and specify future-proofed solutions, which are specifically tailored to their needs.

From retrofitting existing installations to network expansion or complete new installations, the firm can offer guidance in developing the scope of projects, setting objectives and helping to determine the course of action best suited to the customers' requirements, timescales and budgets.

For example, developing new network infrastructure presents great opportunities for utilities to future-proof networks, moving away from traditional design models towards active network management. With the right solution, utilities in the region have the opportunity to leapfrog over the challenges faced by more mature networks and ensure that the infrastructure being developed today meets the challenges of the future.

Adding value through best practice project management

As well as the planned project benefits – such as improved system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) – a well managed and implemented project can deliver wider benefits to customers, adding value, managing costs effectively and delivering creative solutions to challenges as they arise.

A good example of this is the recently completed project undertaken for the Electricity Company of Ghana (ECG), automating almost 50,000 kilometres of distribution lines. ECG serves 2.5 million domestic and business customers across the southern part of Ghana. Its fast-developing customer base and the increasing demands on its network meant improving system reliability was a must.

A bespoke solution was needed to meet all of ECG's needs. Working closely with the customer, Lucy Electric's engineers designed and implemented a tailored, end-to-end, fully integrated distribution automation system. The new system now allows ECG to almost instantly identify and isolate faults and has improved fault resolution times from days to just hours.

During the implementation of the project the team encountered many challenges, including: changing network requirements; difficult to access, remote rural sites with road networks almost impassable in some areas during the rainy season; heavily forested areas with rapid regrowth of vegetation restricting access and radio communications; voltage irregularities; and extreme weather conditions.

...developing new network infrastructure presents great opportunities for utilities to future-proof networks...

Using expert project management skills, the Lucy Electric team were able to react quickly and effectively to the challenges and changing brief, working closely with ECG's engineers and management to make decisions promptly and gain approval for altered installation plans as the project progressed. The positive relationship between Lucy Electric and the ECG was one of main reasons for the project's success. Both parties were able to work together very effectively, aided by the structured project framework.

The Lucy Electric team built strong, collaborative relationships with the customer, using clear and open communication. All project risks were managed transparently, working closely with the local customer teams to resolve challenges and achieve the best result. This had the added benefit of transferring knowledge to the local teams and developing local skills. The Lucy Electric team also made effective use of local resources to manage costs effectively, making the most of local support and knowledge.

Likewise, the firm has also been working with Kenya Power (KPLC) on an ongoing project to automate the network in the Mombasa region. Lucy Electric designed and installed a bespoke distribution automation system (DAS) for both the overhead and ground-mounted 11kV and 33kV electrical distribution network in Mombasa and the surrounding areas within the Coastal Region, covering 1,661 square kilometres.

In common with the ECG project, the team had to address many challenges during the project delivery. In addition to time and budget constraints (the system was installed in 18 months under strict cost controls), the team had to deal with the challenging climate and geography of Mombasa, as well as the difficulties presented by the existing infrastructure.

The project has delivered significant benefits, with the average fault response time reduced from 1–2 hours to just 30 seconds. The system has allowed Kenya Power to remotely locate faults within seconds and the bespoke switch control system enables the technicians to isolate the fault or to determine if it is a substation problem. As a result, customer minutes' offline have been reduced from 1–2 hours to less than 50 seconds.

A key factor identified by the client in the successful delivery of the project was the strong project management skills of the team resulting in a positive ongoing working relationship.

For companies looking at investing in major projects, the choice of partner is critical to ensure successful delivery. However, well-defined, major projects delivered over a significant time period will need to address unforeseen issues and changes. ESI

Data on the project for the Electricity Company of Ghana taken from Dr Kwaw Obu-Cann, General Manager, Supervisory Systems, ECG and John Gemegah, Manager, Supervisory Systems, ECG: presentation at African Utility Week 2016. Data on the project for Kenya Power taken from white paper written by Eng. Samuel Ndirangu, Kenya Power, and presented at African Utility Week 2014.

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The TLC factor should be the foundation for African countries and others around the world seeking to benefit from the rapid growth of clean and renewable energy, writes Angelina Galiteva.

The Foundation for Effective Renewable Energy Regulation

As renewable energy transitions from a niche application to supplying ever-larger amounts of energy on the grid, it is worth looking back 20 years and identifying some of the major factors that enabled the industry to make steady progress along the way. Learning from the mistakes and successes of the past can help enlighten and improve global future energy decisions.

In the United States, and particularly in my home state of California, renewables have flourished in jurisdictions that have a strong policy mandate for renewable energy, while embracing three foundational principles – transparency, consistency and longevity, also known as the TLC factor! Jurisdictions that have successful renewable energy programmes have adopted rules that are transparent and easy to implement. The rules are consistent, easy to administer across the board, and fixed for a specific term (10–20 years). These factors create security

“Learning from the mistakes and successes of the past can help enlighten and improve global future energy decisions.”

and predictability in the market, which in turn generates investment, increased production volumes and lower costs. TLC should be the foundation for African countries and others around the world seeking to benefit from the rapid growth of clean and renewable energy.

In addition to the TLC rules for the development of renewable resources, a successful programme includes clear regulations governing interconnection, inspection and building standards for both large-scale projects (50MW and higher) and smaller customer owned systems. If the interconnection process to the grid is not streamlined, programmes can stall as projects struggle to come online. In California, improved programme administration and interconnection have enabled solar PV installations to increase from 85MW in 2010 to over 12,000MW in 2016. Large-scale wind power projects have also more than doubled in capacity, from 3,000MW to over 6,000MW in the same timeframe.

For residential, commercial and industrial projects, complicated and inconsistent building and safety standards result in unnecessary delays, confusion and cost increases. In the early 2000s, as solar programmes were starting to ramp up, it was a surprise that solar residential installations in California were significantly higher in cost than in Europe and the installation rates were much lower than expected. The price increase was due to the high 'soft costs' – such as burdensome and inconsistent utility requirements for interconnections around the state and different building and safety requirements for municipalities across California.

Providing permits for customer owned systems was difficult and costly, and numerous installers complained that they had lost jobs and customers due to increased costs, which resulted from a 90 day or longer waiting period. In comparison, installers in Germany, had a standardised process and they were able to get a solar system installed and operational in less than a week with significantly less paperwork and a streamlined approval process. In response to this issue, the California Solar Electric Association (SEIA) and other civic organisations, led a grass roots effort to facilitate the introduction of statewide

> *"Mistakes made by early adopters can inform jurisdictions, regions and nations scaling-up their power generation portfolios."*

standards for both utilities and building departments. As a result, the streamlined and uniform standards adopted in California have reduced waiting periods for consumer solar installations from 90 days to less than 3 days, resulting in significant cost reductions and a significant increase in solar system penetration. Today Californian utilities report interconnecting over 8,000 residential solar systems to the grid every single month and that rate is growing.

California is not alone in experiencing tremendous growth in the renewables sector. Countries in Europe with strong pro-renewable regulations report that over 90% of new power installed in Europe in 2016 came from renewables. Bloomberg New Energy Finance (BNEF) reports that renewables – led by wind and solar – are expected to account for over 65% of global energy investments by 2040. This projection should increase as storage technologies become cheaper and more robust, power grids more sophisticated and renewable generators (whether state-owned or IPPs) become better able to provide grid services, effectively eliminating the need for fossil fuel generation as back-up power.

Cities, states and countries are taking leadership roles in calling for high percentages of renewable energy. Targets from 50% to 100% are increasingly common. Especially in the context of climate change, transitioning to renewables on a global scale is an issue of 'when' and not 'if'. And that inevitable transition is making the energy sector a key driver of innovation, economic growth and job creation, with correlated developments in energy efficient grid technology, electric vehicles and hydrogen fuel cars. Renewables are not just displacing fossil fuel power plants. They are charting the way to an interconnected high-tech power system of the future in which clean energy meets all of our power, heating, cooling and transportation needs.

Over the past two decades energy regulators, power providers and grid operators have learned from the mistakes of the past – short-term planning, boom- and bust-cycles for technologies, inadequate incentives, picking technological winners, inconsistent regulations, etc. – and that is good news. Mistakes made by early adopters can inform jurisdictions, regions and nations scaling-up their power generation portfolios. Indeed, countries in the world's Sun Belt can leapfrog technologies and transition directly to the renewable energy future at lower costs, much more efficiently and on an accelerated schedule.
In this context, African nations can become the global leaders in implementing the distributed, digitised and increasingly decarbonised state of the art energy portfolio without the burden of old infrastructure or stranded assets. Let it be so! ESI

ABOUT THE AUTHOR:

Angelina Galiteva actively works to structure and advance the implementation of cutting-edge energy policies that reflect the increasing role of renewable energy, storage, mobility and distributed energy technologies worldwide. She is the founder and Chair of the Board for the Renewables 100 Policy Institute and serves as the Chairperson for the World Council for Renewable Energy.

The renewable energy (RE) landscape, regarded to be in an infant stage of development, is proving to be a catalyst driving technology and policy innovation in the world's mega cities, writes ESI Africa.

RE driving mega cities' transformation

Capitalising on the RE sector is taking global economies by storm and according to the Council for Scientific and Industrial Research (CSIR), an African research and development organisation, South Africa is no exception. Since the introduction of the country's RE Independent Power Producer Procurement Programme (REIPPPP), this versatile sector has added $291.5 million to the country's economy.

In a study conducted by the CSIR, the net economic benefit of renewables achieved (particularly solar photovoltaic and wind) included the calculated benefits of reduced unserved energy (load shedding), as well as cost savings to national power utility, Eskom, which avoided coal and diesel burn. This revelation can be associated with the 2016 International Renewable Energy Agency (IRENA) report, *Renewable Energy in Cities*, which presents an analysis on the role cities can play in the transformation of the energy system when fully exploiting the resources.

Here IRENA explores different scenarios according to scales of economies in cities in terms of energy demand between now and 2030. The study predicts that cities in emerging economies, with population growth above 2% per year, for example, will account for 70% of global growth in energy use by 2030. In order to meet such a demand, the report provides practices, policy and technology options that cities can deploy. The recommendations focus mainly on buildings, heating, cooling and cooking as well as transportation.

Municipal governments taking charge

The IRENA analysis notes that mayors and municipal governments are playing an increasingly central role in accelerating the switch to renewable energy. A case in point is South Africa's City of Cape Town that, in 2014, launched a set of guidelines and associated tariffs for small-scale embedded energy generators, with a generation capacity of less than 1MVA. The guidelines and tariffs were compiled for commercial, industrial and residential generators, applicable to both renewable energy generation and co-generation projects. Small-scale generators have since been permitted to connect to the grid and in so doing are enabled to both import energy from and export a limited amount of energy onto the City's grid, which they will be credited for.

Expanding on the progress of this legislation, Head of Green Energy for the City of Cape Town Brian Jones told ESI Africa that the national regulation for small-scale imbedded generation is still awaited from the national energy regulator. Jones emphasises that "this is crucial to accelerate the uptake of imbedded generation in the country. Draft legislation has been circulated but for some reason it has not been finalised".

"At the moment, approved installations in Cape Town for residential property stand at 102, and for commercial and industrial at 48, and there are another 96 applicants that have obtained permission to install. So the numbers are picking up," he says. In terms of promoting this development, Jones explains that the City has established an energy directorate with electricity generation and distribution under one legislation and new legislation for the sustainable energy market.

With regard to lessons learnt from the initiative, Jones says once grid parity is achieved globally, people will start connecting to the grid – even illegally, if there is no programme in place. He concludes: "Utilities can't ignore the phenomenon that small-scale imbedded generation is. They [utilities] will have to mainstream it into their planning – as a factor on their income streams and a factor on their grid; and it has to become a central part of their operations."

Another game-changer in the energy sector sphere was emphasised last year, when Scott Wiener, Democrat for California State Senate District 11 San Francisco & San Mateo County, proposed a legislation that requires the installation of solar panels on new residential and commercial buildings constructed in San Francisco.

> *"The world's big cities will need $375 billion of investment to curb climate change."*

The legislation's mandate calls for all new buildings up to 10 stories, both residential and commercial, to use either solar panels for electricity or a solar system to heat water. According to Wiener, the legislation has the support of the San Francisco Commission on the Environment, the US Green Buildings Council, the Building Inspection Commission, and Brightline Defense, a non-profit organisation that supports the creation of sustainable environments in low-income communities.

San Francisco has a goal of meeting 100% of its electricity needs with clean energy by 2025. "Cities have to make hard decisions on investments, so it is important to go back to the basics and understand where the opportunities are, what measures offer the greatest potential for energy efficiency improvements, which sectors to prioritise, and what the implementation constraints are," noted Anita Marangoly George, former senior director, energy and extractives global practice at the World Bank.

George made this emphasis in the Bank's Energy Sector Management Assistance Programme: a global knowledge and technical assistance partnership administered by the financial institution, funded by various developed countries.

Transportation powered by clean energy

As of 1 January 2017, trains in the Netherlands began operating completely on clean energy produced by wind power – an impressive achievement in that the initiative beats its own deadline, which was set to be achieved by 2018. NS Dutch Railways partnered with energy company Eneco to use its wind turbines to generate the energy needed to power all of its electric trains. The railway company is the world's first railway company to get 100% of its energy from wind energy and it is reported that annually it consumes 1.2 billion kWh of wind electricity.

In a similar venture at the beginning of 2016, South Africa's City of Cape Town announced that in its efforts to reduce carbon emissions, it will be issuing a tender for the procurement of electric buses for the city's MyCiTi bus service.

"The procurement of the electric buses affirms our commitment made at COP21 in Paris where I committed to ensure that the City of Cape Town takes decisive action and pursues ambitious climate action projects that are not only beneficial to residents but most importantly, the environment," Mayor Patricia de Lille said.

In conclusion, with amplified financing and supporting policies, renewable energy resources – even in developing economies – indicate a possible clean future. One that promises to meet commitments made at COP21 in Paris. ESI

Cities band together against climate risks under C40 umbrella

Created and led by 83 member cities around the world, the Cities Climate Leadership Group (C40) focuses on tackling climate change and driving urban action that reduces greenhouse gas emissions and climate risks. The organisation, guided by a rotating steering committee of C40 mayors, provides strategic direction and governance.

During a C40 seminar held in 2016 in Mexico, the organisation's newly elected president, Paris Mayor Anne Hidalgo, stated that the world's big cities will need $375 billion of investment to curb climate change. The current steering committee members include: Tokyo, Hong Kong, Johannesburg, Jakarta, London, Seoul, Los Angeles, Copenhagen, Milan, Boston, Mexico City, Amman and Rio de Janeiro. Other city members in Africa include: Accra, Addis Ababa, Cairo, Cape Town, Dakar, Dar es Salaam, and Durban.

Rising energy costs and South Africa's high solar potential mean there is a significant opportunity for solar-generated heat, or solar thermal energy generation.

Business case for solar thermal in South Africa

According to the University of Cape Town's Energy Research Centre (UCT's ERC), 79% of the agri-processing sector's energy demand is for low temperature heat. As low temperature heat is provided most economically by solar thermal this represents a key opportunity. Work by GreenCape, in conjunction with Stellenbosch University's Centre for Renewable and Sustainable Energy Studies (CRSES) and the World Wildlife Fund (WWF), estimates the potential for solar thermal energy within the agri-processing sector to be between 425,000m^2 and 3,758,000m^2 of collectors. This could result in savings of 111,000 to 943,000 tonnes of CO_2e emissions per annum (a high variation due to different data sources). Solar thermal presents a key opportunity that can: reduce energy bills, ensure compliance with sustainability objectives and reduce companies' carbon footprints. These benefits could be amplified, as the sector has been identified as one of national importance with policy support for the sector through the Agri-park programme and the Industrial Policy Action Plan.

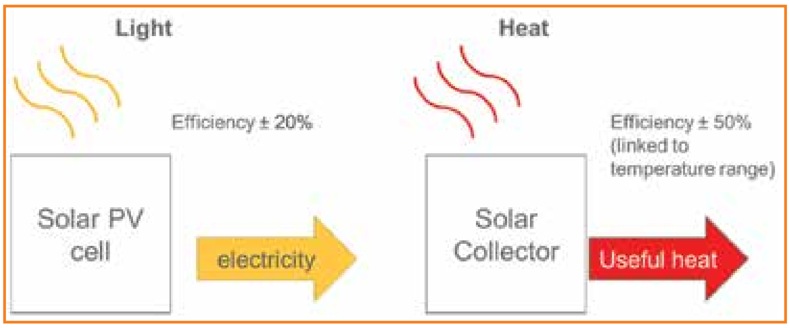

Figure 1: Comparison of solar PV and solar thermal

What is solar thermal energy?

Solar energy, which uses the sun's energy, rather than fossil fuels, is divided into categories, as shown in Figure 1. The light from the sun can be harnessed through photovoltaic (PV) modules to generate electricity; or heat from the sun can be harnessed using solar collectors to provide useful heat. The focus of this article is solar thermal where heat from the sun can be harnessed using solar collectors to provide useful heat.

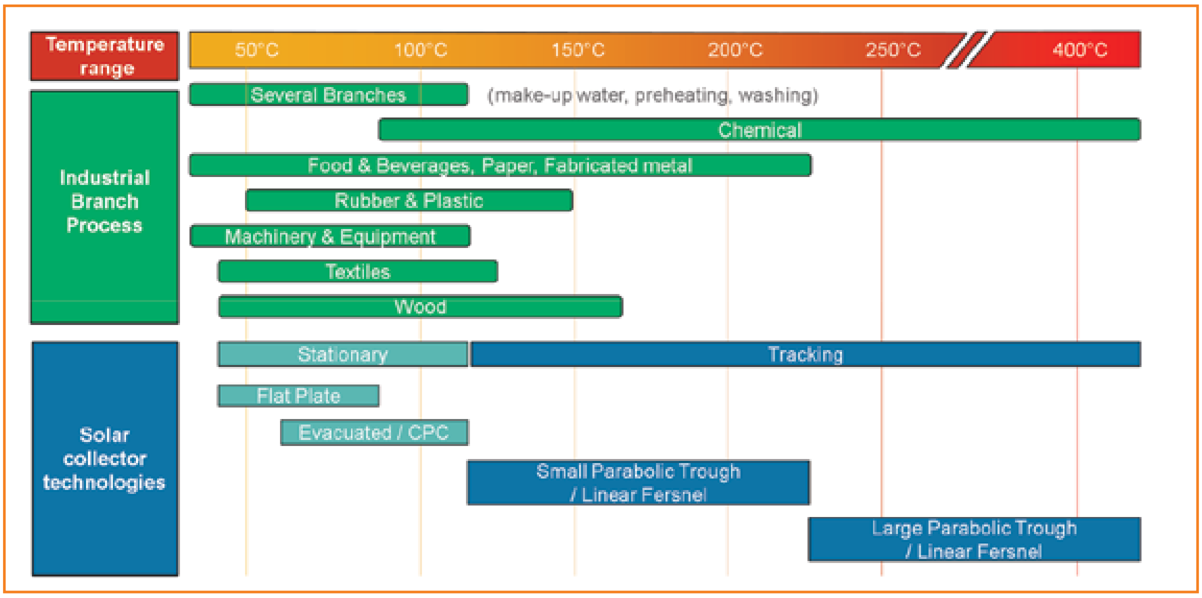

Figure 2: Stationary and tracking solar collector technologies related to operation temperature and process temperature range in different industrial branches. Adapted from Horta, (2015).

Why solar thermal and agri-processing fit effortlessly

Globally, South Africa has some of the highest irradiation, or solar energy reaching the ground. In spite of this, the country has far fewer solar thermal systems installed (1,055MWth) than European countries such as Austria (3,5451MWth), which has three-and-a-half times more systems, and Germany (12,281MWth), which has 12 times more systems than South Africa.

There is a wide range of solar thermal technologies with a wide range of temperature applications. However, the lowest temperature ranges can be supplied the most economically by solar thermal in comparison to other temperature ranges. Solar thermal is therefore a good fit for sectors, like the agri-processing sector, which require low temperature heat. Figure 2 shows a few sectors, the temperature ranges and the types of solar collector technologies that are able to provide these temperature ranges. The solar thermal systems needed increase in complexity as the temperature ranges rise.

Agri-processing – which includes food, beverages, textiles from natural fibres and wood products – has a wide range of processes requiring low temperature. This means that lower cost solar thermal technologies such as flat plate or evacuated tube collectors can provide heat without the need for more expensive solar thermal systems that achieve higher temperatures by concentrating solar energy.

Solar thermal guidelines

For companies considering solar thermal energy for industrial processes, the following, based on the Southern African Solar Thermal Training & Demonstration Initiative's (SOLTRAIN) course on Solar Heat in Industrial Processes, can assist in decision-making:

- The solar fraction (share of heat provided by solar energy) of systems in South Africa is generally in the range of 60-80%. This can be used to estimate the cost savings of the system, which, once paid off, can continue to provide free energy. In general, solar thermal systems supplement traditional fuel sources and do not completely replace them.
- As a first pass, a system efficiency of 50% can be assumed, i.e. about half of the solar energy that reaches the surface will be turned into useful heat. This, in conjunction with a free solar map (such as from Solar GIS) will provide a rough estimate of the energy that can be generated for a specific site and the size of the solar thermal system needed.
- While the costs of solar thermal systems still vary greatly, a study of 89 systems found an average cost of €603 ($647)/m^2. When considering the business case for substituting different fuels, this results in a reasonable business case when replacing all fuels, except possibly coal, as shown in Figure 3. The payback is typically less than 10 years, with an expected lifespan of 20 years: this amounts to 10 years of free energy. Cognisance of differing applications is taken into account with the error bars; thus when replacing electricity and assuming no electricity cost increase the payback period could be as low as four years. Payback periods of less than three years are possible for some instances when replacing diesel, petrol and LPG – again assuming no fuel cost increases.
- Best practice for solar thermal is to consider the energy efficiency of the facility simultaneously, as solar thermal systems are optimised for specific temperature increases that could change as energy efficiency practices are implemented.

Barriers

There are a number of barriers to the development of this market that will need to be addressed. These are briefly discussed below.

Limited knowledge and experience of solar thermal in the agri-processing sector. The technology is not as well known as

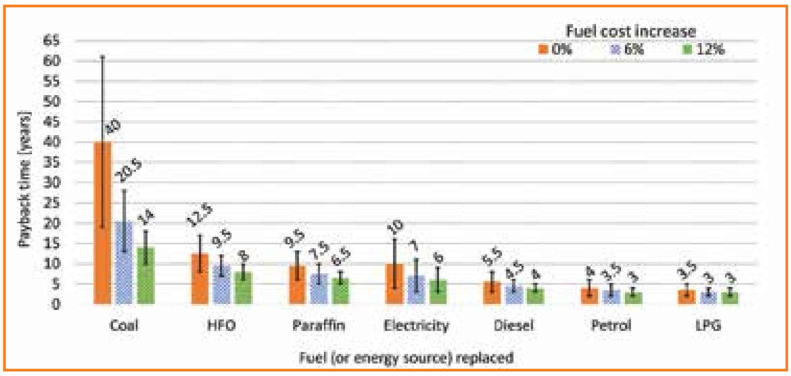

Figure 3: Payback periods of current large-scale solar thermal system when substituting conventional energy sources at different fuel cost increases (0%, 6% and 12%).

Installer & Year	Beneficiary Industry	Collector	Gross Area [m²]	Storage Volume [litre]
HBC 2012	Automobile	Evacuated tube	200	24,200
RENU Holdings 2013	Logistics	Evacuated tube	67.5	5,000
E3 2015	Food & Beverage	Flat-plate	120.6	10,000
Solarzone 2012	Horticulture	Flat-plate	288	20,000
1Energy 2013	Textiles	Evacuated tube	100	22,000
1Energy 2012	Food & Beverage	Evacuated tube	90	4,000
1Energy 2012	Water Treatment	Evacuated tube	75	2,000

Table 1: Extract from database of large (>10m²) solar thermal installations in South Africa, detailing installations for process heat application

other renewable energy solutions, such as solar PV. One of the most important aspects often not communicated is the efficiency of solar thermal (ranging from 40% to 65%), compared to the 20% efficiency of solar PV systems. This higher efficiency makes solar thermal ideal when space to place collectors is constrained.

Perception as a 'new technology'. While the technology is considered new and untested, the database for applications of solar heat integration in industrial processes references systems that were installed more than 35 years ago. South Africa also has a number of industries that have already identified solar thermal as a significant opportunity, as illustrated in Table 1.

Solar thermal systems in South Africa are expensive when compared to solar thermal systems internationally.[2] Additionally, the cost varies greatly, indicative of the relatively underdeveloped solar thermal market in South Africa. Ideally, as more systems are installed and competition increases, prices will fall.

The government's policy of systems, rather than component testing. As only systems (not individual components) are locally (SABS) certified, the local industry is not able to focus on the manufacture of specific components in a solar thermal system. This limits competition and the growth of the sector.

Business case for solar thermal systems

In spite of these barriers, rising energy costs in South Africa mean that there is a good business case for solar thermal systems. Some industry leaders have already identified this opportunity and there are already solar thermal systems providing process heat across the country.

The high capital cost of systems need not be a hindrance, as innovative service models, such as energy service companies (ESCOs), are helping to cover the capital costs. Instead of selling the technology to companies, ESCOs remove the capital cost burden and sell the energy or energy savings to their clients.

The recently launched ESCO register created by the South African National Energy Development Institute has also made it easier to find ESCOs. Additional support is also available from SOLTRAIN in the form of free training, knowledge and financial support for installations that can serve as demonstration sites. With its applicability to agri-processing, solar thermal presents a significant opportunity in a sector set to grow rapidly. ESI

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Bill Girling, hydropower development director at the International Hydropower Association (IHA), uncovers the complexities and challenges of operation and maintenance (O&M) of hydropower facilities across the world.

O&M challenges in Africa's hydropower sector

Conventional hydropower plants are among the lowest-cost electricity-generating resources, due to their long life span and relatively low operating and maintenance (O&M) costs. Nonetheless, hydropower facilities are finding O&M increasingly complex.

The civil infrastructure of hydropower facilities can last well in excess of 80 years, whereas mechanical and electrical components may require replacement in less than 50 years, depending on the operating role of the hydropower plant. Base load plants with minimal daily load variation can operate over a longer period than plants operated to meet peak load requirements and frequency control operations, where significant start-stop operations may be required.

The O&M of hydropower facilities is particularly challenging when the owners of aging facilities are faced with strategic asset replacement and/or refurbishment decisions. For example, in North America, a significant proportion of the existing fleet of hydropower mechanical and electrical equipment is reaching its life expectancy. For this reason, project owners are often facing difficult economic decisions between overhaul and replacement.

In developed countries with significant hydropower assets such as Canada, US, Norway and Iceland, basic O&M practices such as regular inspections for cavitation damage on turbine blades, stator and rotor windings, bearings and excitation systems are based on well established guidelines and are generally carried out under a scheduled work programme. The key challenges facing project owners and operators is to develop an optimised asset management strategy that targets safety and maximises unit availability – with a fleet of aging assets reaching the end of their useable life, compounded by an aging workforce – and to complete this work on time and on budget.

Common strategies employed in developed countries include implementing remote operation at older facilities, installing real-time asset monitoring systems, maintaining key spare components on-site to reduce outage time, and other solutions to minimise O&M costs. Asset managers are increasingly implementing sophisticated risk-based decision-making tools to optimise their near-term and long-term O&M asset management plans for maintaining, overhauling or replacing the most critical components of their fleet.

In less developed areas of the world, including many countries in Africa, South Asia and South America, a unique set of challenges for operating and maintaining hydropower assets exist. Often, developing nations face institutional challenges such as a lack of training to operate and maintain facilities, lack of dam safety enforcement and compliance, limited access to spare parts and lack of financial support.

Beyond these challenges, other regional issues can add an additional level of complexity to their O&M challenges; including climate extremes (droughts and floods) and sedimentation problems, which can compromise conventional O&M practices.

Specific challenges for hydropower O&M in Africa

At a recent workshop hosted by the World Bank Group and SECO (Swiss State Secretariat for Economic Affairs) in Martigny, Switzerland, stakeholders from a broad cross-section of the hydropower community gathered to discuss O&M challenges, with a specific focus on developing a better understanding of the main O&M challenges in several countries in Africa including Cameroon, Uganda, Rwanda and Sao Tome.

A number of common O&M issues were observed consistently across all of these African countries. In all cases, there was a preponderance of insufficient training on best practices in O&M and a lack of knowledge sharing across the hydropower sector. In most of these African utilities, there was no formal maintenance optimisation programme in place to prioritise maintenance around available budgets and staff resources, to target the most critical components requiring maintenance; often resulting in extended forced outages and lost revenue.

Many African countries are dealing with inadequate financial resources to procure spare parts for critical components requiring replacement; often lacking the appropriate decision-making tools to put forward a business case for mitigating these preventable forced outages by purchasing spare parts to keep on site. Insufficient financial support is also a barrier to most countries having the capacity to undertake any major rehabilitation or refurbishment projects.

> *“A number of common O&M issues were observed consistently across all of these African countries.”*

Another common theme amongst African utilities is a loss of production revenue associated with sub-optimal operating strategies, resulting in lost revenue from inefficient unit operation and spilled energy, ultimately impacting funds available for ongoing maintenance. For example, in a case study of the Sanaga River complex in Cameroon, operational issues such as inconsistent, poorly defined operating rules and a lack of basin management strategies have resulted in increasing sedimentation of the reservoir.

In specific cases, political interference and cross-border disputes have severely restricted the utility’s capability to carry out optimal O&M practices. In Rwanda, the different legal status of two existing hydropower plants (Ruzizi I and Ruzizi II) and the recent creation of a new authority for water management of the Kivu Lake and the Ruzizi River have resulted in separate power dispatching between Ruzizi I and Ruzizi II.

In many countries in Africa, there is an absence of a regulatory framework to monitor safety of hydropower infrastructure and in particular a lack of enforcement around dam safety guidelines.

In order for African countries to progress in terms of building the capacity and knowledge to implement successful O&M practices into their respective hydropower facilities, good practice guidelines need to be developed with the assistance of hydropower operators from developed countries, to ensure that the following O&M practices can be adopted:

1. Hydropower stations should be operated within the context of the management of the entire watershed (considering both upstream and downstream impacts) when developing long term O&M plans, to optimise efficient management of water supply, minimise erosion and reduce sediment problems.
2. Implementing a long-term strategy for O&M is essential, including (where possible) the inclusion of long-term O&M contracts, and a well-planned O&M programme to motivate staff and put methodologies in place to invoke capacity building.
3. Better communication between the asset owner and stakeholders responsible for corporate social responsibility and emergency preparedness is necessary to promote the financial and economic attractiveness of a good O&M programme.
4. A policy that addresses the need for standardisation of equipment is needed.

Building capacity at the international level

The International Hydropower Association is working with international institutions such as the World Bank Group to improve understanding of strategies for O&M in the sector and identifying international good practices. The next meeting bringing together industry, financial institutions and government officials for that purpose will be the 2017 World Hydropower Congress, hosted by the African Union Commission from 9–11 May 2017, where O&M and modernisation issues will feature prominently. **ESI**

This article is an extract from the 2017 Hydropower Status Report, which the IHA will publish in full in April 2017. www.hydropower.org

Kaplan turbine

Hydropower project implementation is always capital intensive with high upfront investment, needed hence creating a perceived risk among financiers and lenders.

High cost of a Kaplan turbine project: The ‘whys’ explained

Fund lenders naturally ask why a Kaplan project, with similar capacity output, is costlier than other types, such as a Francis project, and they honestly need adequate explanations. This article aims to provide explanations for these ‘whys’ by reviewing and analysing historical records and highlighting major cost drivers for such assets across the globe to establish specific cost of installations of Kaplan and Francis turbine units.

Financial institutions are always keen to ensure that hydropower projects’ construction risks are manageable among a host of other risks. Other risks that may be considered for developing a hydropower project include foreign exchange, repatriation, sovereign

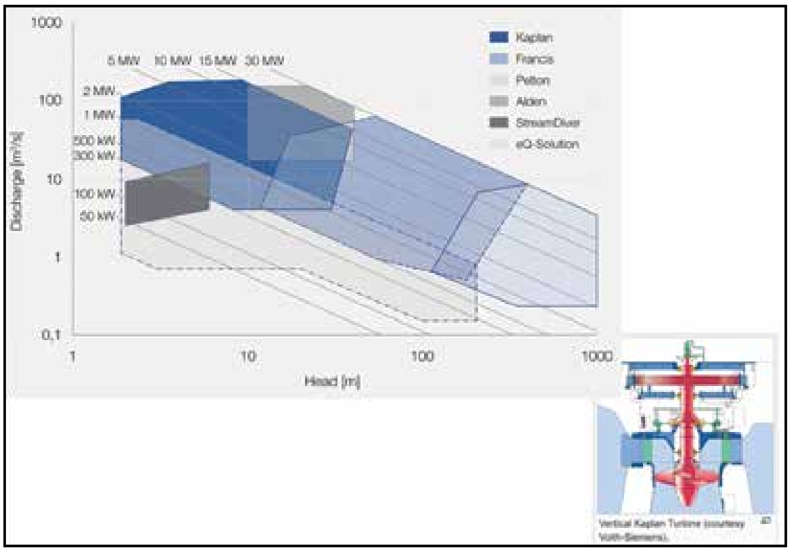

Figure 1: Turbine envelope chart. Source: Voith

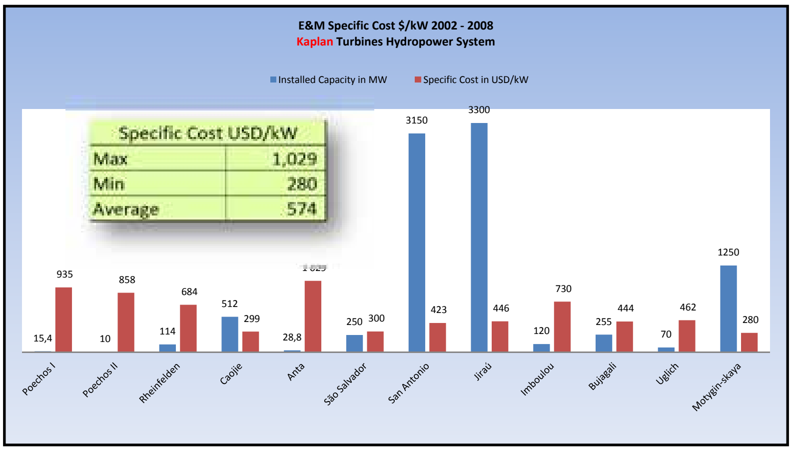

Figure 2: Specific cost of installation for Kaplan turbines*

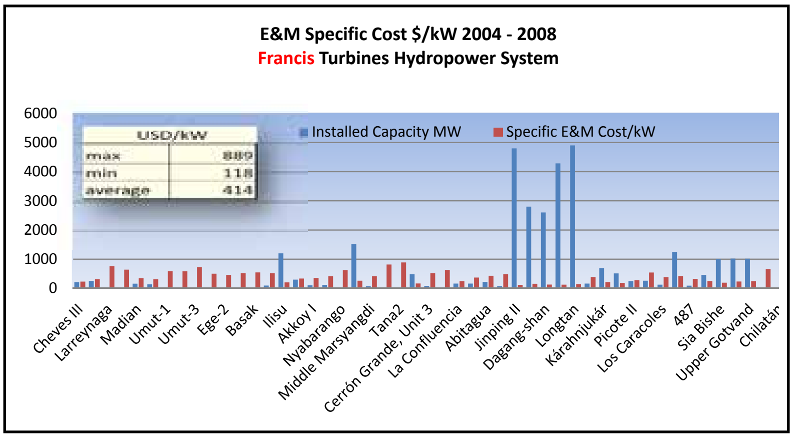

Figure 3: Specific cost of installation for Francis turbines*

(country risk), interest rates, inflation rates, changes in legislative, market risks (for non-existence of PPA), revenue, payment (due to a lack of creditworthiness of the offtaker) and hydrological risks. Although these aforementioned risks may differ from country to country and are more likely to be present in emerging markets than in developed economies, financing a hydropower project is heavily dependent on the prudent management of such types of risks.

Thus, when a bank is faced with limited financial resources for several competing projects of similar capacity output, it is logical to seek a comprehensive understanding of why one project would be more expensive to implement than another so that an informed decision may be made by the financier before committing financial resources to develop such energy projects.

Kaplan turbine cost benchmarking

Experience in the hydropower sector indicates that Kaplan turbine projects appear to be more costly to build when compared to other types in the peer group. Taken from an extensive literature search on specific cost for water power turbines around the globe, the data shown in Figures 3 and 4 indicate quite interesting results in respect of specific cost of installation per kW for both Kaplan and Francis projects.

The **Kaplan** plants examined are 12 with installed capacities ranging from 10MW to 3,300MW. Plants with 10MW to 28MW installed capacities constitute about 25% of the plants examined, whereas 75% of the project population sizes have capacities ranging from 70MW to 3,300MW. The maximum specific cost of installation among the examined Kaplan projects is $1,029/kW, while the minimum value is $280/kW and the mean value found among the plants examined is $574/kW.

*Footnote: * Data reviewed and collated by L. Kassana from Water Power www.waterpowermagazine.com/news/newstable-1-6-2052186*

Evolution of the Kaplan turbine

The variable geometry turbine invented by Austrian engineer Victor Kaplan (Ph.D) is used today in hydropower plants that operate in low head and high flow hydro regimes – be it run-of-river schemes or where a wide range of operating flexibility is needed. The Kaplan turbine is a propeller-type water turbine with adjustable blades, developed in 1913 by Prof Kaplan who combined automatically adjusted propeller blades with automatically adjusted wicket gates to achieve efficiency over a wide range of flow and water level. The Kaplan turbine was an evolution of the Francis turbine. Its invention allowed efficient power production in low head applications that was not possible with Francis turbines (see Figure 1 for operating heads and discharge ranges).

The **Francis** plants examined are about 50 with installed capacities ranging from 4MW to 4,900MW. Plants with 4MW to 30MW installed capacities constitute about 30% of the plants examined, whereas 70% of the plants have capacities ranging from 72MW to 4,900MW. The maximum specific cost of installation among the examined ~~Kaplan~~ Francis projects is $889kW, while the minimum value is $118/kW and the mean value found among the plants examined is $414/kW, as shown in Figure 3.

Experience on several projects in Africa indicates the market costs of the electromechanical equipment for projects within the range of 1MW to 10MW for a typical 'water to wire' package from European suppliers as being:

- Pelton projects: 300 ~ 500 USD/kW
- Francis projects: 400 ~ 700 USD/kW
- Kaplan projects: 800 ~ 1 300 USD/kW

Major cost drivers

Note that hydropower projects are always site specific in terms of terrain/ topography, geological and hydrological conditions.

> The Kaplan machine being a 'low head and high flow' scheme will always require more steel (tonnage) and machining.

> In addition, the Kaplan project would typically operate at lower

speeds than the Francis or Pelton technologies, hence requiring a larger generator for the same power output. The larger the generator is, the more expensive it is in relation to the alternative turbines within the same peer group.

> The size and weight of the electromechanical equipment also has an impact on the power station design as the overhead crane, and its support structure, needs to be designed to handle the weight for erection purposes. These pertinent structures result in more costs than would have been the case with other turbines.

> Furthermore, due to the larger volume of water conveyed from the intake to the power station, the infrastructure required is obviously larger and hence more expensive. As an example, a fictitious comparison between a Francis project compared to Kaplan's required infrastructure is provided below. This illustrates the sheer size to be dealt with compared to the typical Francis project.

> In this fictitious example, a typical Francis project with a similar capacity output, conveying 2.5m^3/s of water requires a 1.2m diameter pipe or a 1.0m wide x 1.4m high canal. In Kaplan's case, using the same velocity parameters in the pipe/canal, due to the higher flow of 13m^3/s, which is more than five times the flow stated above, one would consider a 2.6m diameter pipe or a 3.0m wide x 2.8m high canal. This sheer size of conveyance (canal/low pressure pipe and penstock) system for the Kaplan project means more cost than it would have been for a Francis system with the same power output.

> Again, taking into consideration the steep slopes where such a water conveyance system would be constructed, one would have to excavate additional space in the flanks to place this structure (shown as a pipe for illustrative reasons in Figure 4), resulting in additional earthwork costs. Note that the additional excavation shown here must be multiplied by the entire canal/water

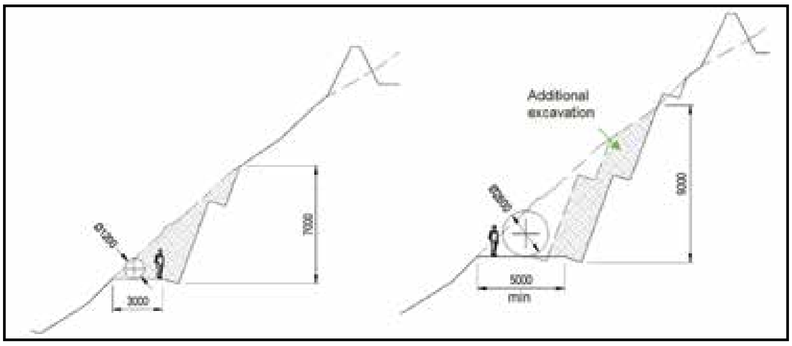

Figure 4: Typical comparative excavation profile for the 1.2 m dia. pipe versus the 2.6 m dia. pipe

conveyance length to gauge the volume to be excavated.

> Furthermore, associated costs for protection works for the Kaplan project will be higher than those for a Francis project.

> Furthermore, the equipment required during construction/installation (mobile cranes, etc.) to handle and install such large pipes and other equipment as required by the project will all be comparatively bigger, making the costs of the infrastructure much more expensive than for a typical Francis solution.

> The method of excavation differs depending on the ground conditions. Where it is soft excavation, less costly method and 'easy' excavation techniques would apply. However, in case of excavation through hard rock, blasting techniques are necessary, which eventually affects the overall excavation costs significantly.

> Since the sizing of most of the infrastructure (intake, water conveyance, gates, canals, penstock, etc.) is dependent on the flow velocity, if the flow is five times higher, this means that the flow area would have to be five times larger to maintain the same velocity profile. This leads to bigger (thicker) walls, additional hydro-mechanical gates, coarse and fine trash racks (screens), larger de-sanding works, etc.

> Likewise, due to large machinery, excavation and concreting works at the powerhouse will also be much costlier for a Kaplan project than for a Francis project.

The review on the historical erection cost data as presented in this article indeed proves that a Kaplan project is costlier than a typical Francis project. However, as indicated above, an investor/developer is always compelled to select the turbine type due to site-specific conditions related to terrain, hydrology and geology. **ESI**

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