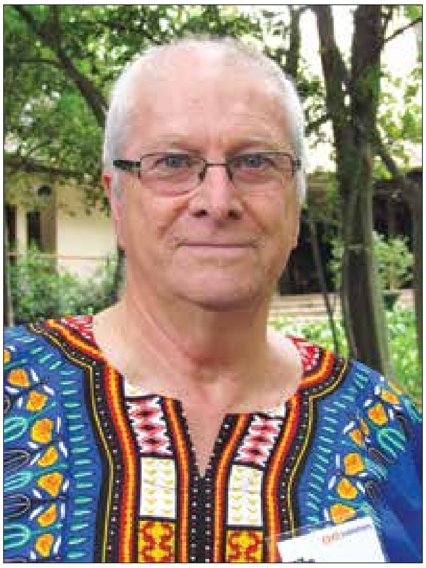
Integrated resource plan for electricity 2010-2030: Update report

Compiled by Mike Rycroft, features editor

The DoE has issued the first update of the IRP 2010 which contains significant changes to the original plan. The plan has been issued for public comment and it is anticipated that it will be submitted to cabinet by March 2014. This article summarises some of the main points.

When the first IRP was issued it was stated that it was a dynamic plan which would be updated and modified as situations changed and more information became available. This is the first update of the original plan. Previous articles have questioned the wisdom of following a policy of large centralised power plants, which have long construction times and have, in the past, resulted in oversupply. Particular focus has been placed on large nuclear which has an extremely long build time and requires financial commitment well before demand is realised. Developments in the power generation market however have provided a great variety of potential game-changers which allow much more rapid responses to variations in demand. To take advantage of these technologies requires a change in the basic principles driving the plan.



Mike Rycroft

Update process

While the IRP 2010 remains the official government plan for new generation capacity until replaced by a full iteration, this IRP update is intended to provide insight into critical changes for consideration on key decisions in the interim.

Expected demand

Actual national electricity demand has been lower over the past three years than expected in the IRP 2010. In 2012 the expected moderate demand was 270 TWh while the actual was 249 TWh. Last year's data is skewed by the application of power buy-backs by Eskom, but notwithstanding this, the underlying trend indicates a lower growth in electricity demand relative to the previous assumptions. Although electricity demand was lower than forecasted, economic activity has been only marginally different from that forecasted. The 2012 lower growth departs from the forecast and has a high impact on the resulting electricity demand.

Changes to base case

The base case is described as the status quo, or "business as usual" case. By updating the IRP 2010 assumptions in five discrete "update steps", a set of new information or changes appears. A number of limitations are imposed in the IRP 2010, in particular an annual limit of new capacity for wind (1600 MW) and photovoltaic (1000 MW). For the purposes of the IRP update these constraints will continue until credible information becomes available on solar and wind conditions and how models can be further developed to analyse the impacts of the stochastic nature of the supply.

Table 1 shows the changes in capacity in 2030 between the updated base case and the original IRP 2010 policy adjusted plan. The total capacity required is a full 8182 MW less than in the IRP 2010 which would have an impact on electricity prices over the next 15 years.

The revised base case shows a significant increase in PV over wind and other renewable technologies compared to the IRP 2010 base case.

Technology options and costs

The costs for generic technologies used in the IRP 2010 were based on the July 2010 EPRI report [1].

This review utilises the updates provided by EPRI for the same technologies; for photovoltaic, sugar bagasse and regional options, the 2010 costs have been inflated with pumped storage costs.

A persistent and unresolved uncertainty surrounds nuclear capital costs. Based on studies and reported project costs for new nuclear investment, generic nuclear capital costs were possibly in the $3800/kW to $7000/kW range. These studies suggest that, outside of Asia, costs for new nuclear capacity equates to $5800/kW overnight cost (in 2012 dollars). This is taken as the generic cost of nuclear capacity for purposes of the update.

This is based on large existing nuclear plant and ignores the possibility of small modular reactors. As no real information is available on costs for these systems, although claims have been made that they will be cheaper than conventional plant, the plan is justified in ignoring them, but they may constitute a game changer in future.

Climate change mitigation

A key issue for extending the study period for the IRP Update to 2050 was to consider strategies to reduce carbon emissions in the period following 2030. The peak-plateau-decline objective suggests that emissions would be allowed to peak in 2025 then plateau for some period before declining. Assuming a 45% contribution, the upper emissions limit for the electricity would be 193 MT/a in 2050 and the lower emissions limit would be 95 MT/a.

Three alternatives are proposed for future carbon mitigation with increasing impact on costs for the electricity sector. These are:

- To continue the emission target established in the IRP 2010 of 275 MT/a. This target establishes a counterfactual for the impact of the target on costs in the electricity sector.
- One approach to the department of environmental affairs' (DEA's) requirement for the peak-platea -decline (PPD) is a moderate decline in carbon emissions, beginning at the 275 MT/a established in IRP 2010 and then starting to decline in 2037 at a moderate pace before reaching 210 MT/a in 2050, which is marginally above the DEA's upper limit target.
- The advanced decline scenario allows for an earlier reduction in carbon emissions from the IRP 2010 limit of 275 MT/a in 2030 before declining at an increasing rate to reach 140 MT/a in 2050, which is well within the DEA's target.

Regional developments

The policy-adjusted IRP only allowed for 2609 MW of regional hydroelectric generation projects, even though it considered an additional 740 MW. A number of additional hydro options have become available. These include:

- The Inga III project in the Democratic Republic of Congo which would allow South Africa access to 2500 MW. It was assumed this would be available after 2025.
- The Kobong pumped storage scheme in Lesotho which forms part of the second phase of the Lesotho Highlands Water Project. This facility will provide 1200 MW of pumped storage capacity from 2023. The utilisation of the facility in the model remained low for the full study period indicating that it may not be the most cost effective use of capital to invest in yet another pumped storage scheme.
- The other hydro projects included in the IRP 2010 were re-introduced in the regional hydro scenario to see if they would still be selected at the costs as indicated in IRP 2010 (with escalation at South African CPI). All four projects (Boroma, Ithezi Tezi, Kafue, Kariba North Extension) are selected between 2022 and 2024, indicating the attractiveness of the options if the original cost assumption is indicative of the true cost.

The only regional coal option considered was Mmamabula in Botswana. This 1200 MW was included in the base case as a fluidised bed combustion option with no emissions (as the emissions accrue outside South Africa and is preferred by the model in all cases before other domestic coal-fired generation).

Embedded generation – rooftop PV

It has become highly probable that electricity consumers (commercial, residential, and to some extent industrial) will begin installing small-scale (predominantly roof-top PV) distributed generation to meet some or all of their electricity requirements. This penetration of distributed generation may occur with or without the support and approval of national and local government entities, but it may be prudent to incentivise implementation in order to derive benefits from this development rather than have a potentially sub-optimal result because authorities considered the risks rather than the benefits.

The assumed penetration of embedded PV uses residential as a proxy (even though commercial rooftop is more likely to materialise especially as there is a better match of electricity supply from PV and the demand on site). It was assumed for the purposes of estimating potential PV rollout in homes that only households in living standard measure (LSM 7) or higher would invest in rooftop PV and that (by 2020) only 50% of these would do so. In these cases the average capacity invested would be 5 kWp. Fig. 1 indicates the estimated growth in total rooftop PV as the number of households in LSM 7, or higher, increases.

Technology option	2030 bassed on IRP 2010 (MW)	2030 based on updated case (MW)
Existing coal	34 746	36 230
New coal	6250	2450
CCGT	2370	3550
OCGT/Gas engines	7330	7680
Hydro imports	4109	3000
Hydro domestic	700	690
PS (include imports)	2912	2900
Nuclear	11 400	6660
PV	8400	9770
CSP	1200	3300
Wind3	9200	4360
Other	915	640
Total (MW)	**89 532**	**81 230**

Table 1: Technology options in 2030 arising from IRP 2010 and the updated base case [2].

The results of this scenario are shown in Table 2 and indicate the preferred technology options in the face of this development, especially as more flexible, mid-merit plant would be required to accommodate the large midday generation that disappears toward the evening peak. This can be seen in the increased requirement of 5760 MW for OCGT or gas engines and an increase in CCGT of 1420 MW by 2050. The nuclear required is less by 3200 MW, whereas the coal generation is much the same as the base case (increase of one unit of 750 MW) by 2050. The CSP capacity is reduced significantly by 6900 MW.

Outlook for natural gas

In the IRP 2010 the main source of potential gas generation was liquefied natural gas (LNG).

This was limited to a maximum 4300 MW of capacity. There was a consideration of the Kudu gas option but this used the parameters from a previous SAPP pool plan. While gas-fired CCGT were evident in many of the scenarios leading up to the final IRP 2010 these were squeezed out by many of the policy options made in the policy-adjusted plan.

In the years since the promulgation of the IRP 2010 there have been a number of new gas finds and developments in the gas market, domestically, regionally and internationally. These have required a change in how the IRP considers gas options:

- In the base case the domestic gas option (which was not considered at all in IRP 2010) is considered at a fuel price of R70/GJ (in 2012 ZAR) but limited in total energy capacity to 295 PJ.
- In the base case regional gas is also considered at a fuel price of R70/GJ and is similarly limited but at 986 PJ. This reflects the Kudu gas field only as it is assumed that the currently operating Mozambique gas fields (Temane and Pande) are already fully committed. The modelling system prefers a mid-merit operation for the gas-fired power plants and builds 2840 MW to utilise the gas in this fashion. If operated in a base-load fashion only 800 MW would be built.
- LNG is still considered available, uncapped, but at a price of R92/GJ, based on an assumed price of \$10/MMBTU. The future price of LNG is assumed to remain at this price in real terms. At this price few of the scenarios consider LNG gas as a viable fuel for midmerit generation, let alone base-load. However it would be feasible for OCGT peaking capacity and thus all new OCGT capacity is assumed to operate on gas rather than the current practice of utilising diesel. The OCGT is assumed to be able to utilise the domestic and regional gas as a first priority and then only LNG if the capacity is reached.
- A principle benefit of CCGT gas generation is the low capital cost which lends itself to midmerit operation. This is supported by the levelised cost comparison between pulverised fuel (PF) coal and CCGT gas which indicates that, at current fuel cost assumptions, PF coal is preferred for operation at load factors above 46% whereas CCGT is preferred below this.
- The development of additional conventional off-shore gas fields in Mozambique, specifically in Sofala province, which would increase the volume available at the R70/GJ price from 2020 by an additional 986 PJ. The large gas fields in the far north of Mozambique (Romvula basin) and Tanzania are not considered in this pool and the distance would lead to higher costs, closer to the LNG price. There may even be an argument that suggests South Africa would be better served to allow this gas to be liquefied and then import it as LNG rather than increase energy dependency on one source of gas.

Technology option	Moderate decline (MW) 2030	Rooftop PV (MW) 2030	Moderate decline (MW) 2050	Rooftop PV (MW) 2050
Existing coal	36 230	36 230	16 120	16 120
New coal	2450	2450	12 700	13 450
CCGT	3550	2840	9230	10 650
OCGT/gas engines	7800	13 440	11 400	17 160
Hydro imports	3000	3000	3000	3000
Hydro domestic	690	690	690	690
PS (include imports)	2900	2900	2900	2900
Nuclear	6660	3460	20 800	17 600
Embedded PV	-	21 617	-	29 778
PV (additional)	9630	8770	25 000	24 930
CSP	3300	700	10 900	4000
Wind	4250	3790	10 680	10 870
Other	640	640	-	-
Total	**81 100**	**100 527**	**123 420**	**151 148**

Table 2: Technology options arising from the Rooftop PV case relative to moderate decline [2].

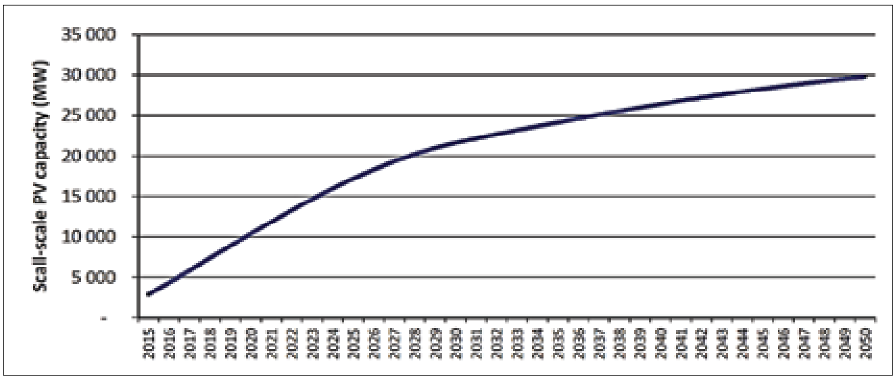


Fig. 1: Estimated growth in rooftop PV [2].

- The potential for shale gas in South Africa, specifically the Karoo, after 2025. The total quantum of potential gas energy is substantial, so imposing any cap for own use makes little sense, but the price of the developed shale gas is highly uncertain. If the scale of the operation remains limited then a price similar to the LNG price (R92/GJ) may be realised, but this would decline as the scale of the shale development increases. For the purposes of the scenario the price of shale is assumed at the R92/GJ mark in 2025 but decreases annually to a low of R50/GJ in 2035. This provides an insight to the tipping point where gas would replace coal-fired generation not only for midmerit operation but also base-load generation.
- The possible decrease in the gas price resulting from an expected large-scale exploitation of shale gas results in a switch in electricity generation from coal and nuclear toward a gas dominated regime along with a more limited renewable fleet. This is similar to the experience of the United States in the last five years as shale gas has revolutionised the power generation industry and allowed the US to reduce carbon emissions through the switch from coal to cheaper gas-fired generation.

Energy efficiency

The IRP 2010 considered only the Eskom projects for energy efficiency demand side management (EEDSM). It was suggested in the IRP 2010 report that additional work would be required to establish a clear indication of the per-unit costs of EEDSM programmes. This work has not been undertaken thus, once again, the update relies on Eskom's assumed programmes. Beyond this, however, the update considers a significant decline in the electricity intensity of the South African economy driven by:

- Changes in the structure of the economy specifically the move from energy intensive industries to less intensive sectors
- Elasticity of demand as higher electricity prices impact on energy consumption patterns
- Regular improvements in technology which reduces the energy intensity of production processes and energy requirements on appliances and other elements of electricity consumption

It is expected that, even without the intervention of a centrally mandated entity, the market will drive some energy efficiency over the next 30 years. However there are limits to market-driven efficiency which still requires an entity to pursue programmes to continue efficiency improvements. These include:

- Electricity retail prices do not reflect the long run marginal cost of electricity and thus the optimal level of efficiency investment will not be attained as the true benefit of efficiency improvement is not realised by the investor
- Access to capital may limit the ability of consumers to undertake the investment required
- Linked to the above is the potentially higher cost of capital for private investors relative to the state which could increase the pay-back period of investments

Thus there is a role for a centrally mandated entity to pursue energy efficiency in order to realise the expected electricity intensity or improve thereon.

Solar park

The concept of the solar park or solar corridor has been high on the government's agenda for a number of years. While the moderate decline delays the construction of CSP until 2030 (when learning rates render these competitive) the solar park test case forces construction earlier, allowing for 1000 MW of CSP construction each year from 2018 to 2022. The result is to delay the nuclear construction in the moderate decline from 2025 to 2030 (but resulting in the same nuclear construction by 2050), whereas most of the other technologies remain much the same as the moderate decline case.

Summary

Since the promulgation of the Integrated Resource Plan (IRP) 2010-2030 there have been a number of developments in the energy sector in South and southern Africa. In addition the electricity demand outlook has changed markedly from that expected in 2010. The demand in 2030 is now projected to be in the range of 345 to 416 TWh as opposed to 454 TWh expected in the policy-adjusted IRP. From a peak demand perspective this means a reduction from 67 800 MW to 61 200 MW (on the upper end of the range), with the consequence that at least 6600 MW less capacity is required (in terms of reliable generating capacity).

The update is also aligned with a shift in economic development away from energy intensive industries which is assumed to dramatically reduce the electricity intensity of the economy allowing the growth rate to have a less imposing impact on electricity demand to 2030 and beyond. The reality is that demand may not reach the levels required (especially not in the next five years) which raises the risk of overbuilding generation capacity to meet the target.

Apart from the uncertainty regarding

the future demand there are additional variables in the energy sector, specifically the potential for shale gas, the extent of other gas developments in the region, as well as the uncertainty in the cost of nuclear capacity and future fuel costs (specifically coal and gas), including fuel availability. All of these uncertainties suggest that an alternative to a fixed capacity plan is a more flexible approach taking into account the different outcomes based on changing assumptions (and scenarios) and looking at the determinants required in making key investment decisions.

The update considers determinants at the turning-points for the investment decisions and provides recommendations on which investment should be pursued under different conditions when they arise. In the shorter term (the next two to three years) there are clear guidelines arising from the scenarios, specifically:

- The nuclear decision can possibly be delayed. The revised demand projections suggest that no new nuclear base-load capacity is required until after 2025 (and for lower demand not until at earliest 2035).
- Procurement for a new set of fluidised bed combustion coal generation should be launched for a total of 1000-1500 MW capacity (as a preferable implementation of the "Coal 3" programme). It is recommended that these should be based on discard coal.
- Regional hydro projects in Mozambique and Zambia may be realised including the infrastructure developments that may have positive spinoffs in unleashing other potential in the region. Additionally regional coal options are attractive due to the emissions not accruing to South Africa, and in cases where the pricing is competitive with South African options, would be preferred.
- The current renewable bid programme should continue with additional annual rounds (of 1000 MW PV capacity; 1000 MW wind capacity and 200 MW CSP capacity), and the potential for hydro at competitive rates.
- A standard offer approach should be developed by the Department of Energy in which an agency similar to Eskom's Single Buyer Office purchases energy from embedded generators at a set price so as to render municipalities indifferent between their Eskom supply and embedded generators and thus support small scale distributed generation.
- Additional analysis on the potential of extending the life of Eskom's existing fleet should be undertaken, to firm up on the costs involved.
- Formalise funding for EEDSM programmes and secure the appropriate mandate for the national entity to facilitate these programmes (possibly with targets on electricity intensity of the economy).

The assessment of the transmission impact of the update indicates that five possible Transmission Power Corridors will be required to enable key generation scenarios. The main difference between these scenarios is the physical amount of transmission infrastructure within these corridors and their timing. The transmission impact assessment has been based on the reasonable spatial location of the future generation taking into account current knowledge and information. Therefore there is still an opportunity to consider better generation location strategies in the longer term.

One generation strategy which could provide advantages in terms of reducing the network integration costs and minimising system losses is to consider a large distributed generation network with more appropriately sized units which can be integrated into the distribution networks utilising their infrastructure and reducing the loading of the transmission grid. This can be achieved with PV, gas and even coal plants located near large loads or major load centres.

It is imperative that the IRP should be updated on a regular basis (possibly even annually), while flexibility in decisions should be the priority to favour decisions of least regret. This would suggest that commitments to long range large-scale investment decisions should be avoided and regional and domestic gas options pursued and shale exploration stepped up.

The summary indicates a move away from large centralised plant to smaller distributed units. Paradoxically this favours nuclear if the development of small modular reactors is taken into account. Several full scale pilot plants are under construction and commercial units should be available around about the time that the decision to commit to conventional plant would be taken. Distributed generation also implies distributed storage, especially for renewables, and this can affect the viability of centralised pumped water storage (PWS) systems. This has not been taken into account in the update.

Reference

[1] EPRI: "Power Generation Technology Data for Integrated Resource Plan of South Africa", www.energy.gov.za/IRP/irp files/Tech Data for Integ Plan of South Africa July 08 2010 Final.pdf

[2] IRP 2010-2030 update report, Department of Energy, 21 November 2013.

Send your comments to: energize@ee.co.za ❖

COAL MILLING

EVEN 100 YEARS OF BEING AN INNOVATOR AND MARKET LEADER DOES NOT KEEP US FROM INVENTING BETTER SOLUTIONS

EVERY DAY

Loesche Coal Mill

Field proven reliable technology and innovative design based on patented modular concept • Design for ease of maintenance • Design performance grinding solutions for solid fuels, including biomass • Specialised retrofit solutions for both mills and classifiers • Turnkey supply

Tel: +27 (0)11 482 2933 | Fax: +27 (0)11 482 2940 | Email: umeyer@loeschesa.co.za | Web: www.loesche.com

LOESCHE
INNOVATIVE ENGINEERING