South African Network Infrastructure Review:

ELECTRICITY

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Purpose

This paper is one of four assessments of South Africa's network infrastructure systems carried out by an expert panel on behalf of the government.

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Note

This paper was written initially in 2007. In previous years, South Africa had enjoyed a reliable and cheap supply of electricity. That situation changed dramatically in 2008 with regular load-shedding and sharp increases in electricity prices. The data and analysis in the paper largely reflect the pre-2008 situation; nevertheless, many, if not most, of the policy recommendations remain relevant.

Contents

1. OVERVIEW

The generation and distribution of electricity will play a major role in South Africa's economic future. This report:

1. Examines the structure of electricity supply in South Africa
2. Assesses the efficiency of electricity provision
3. Diagnoses the causes of inefficiency relating to market structure and regulatory capacity
4. Identifies areas of market dominance and monopoly abuse and proposes regulatory safeguards
5. Identifies major regulatory issues that need to be addressed and proposes a strategy for addressing these issues.

Options for restructuring are examined according to their ability to enhance efficiency, market responsiveness and fiscal responsibility of the sector. We conclude that the potential for radical restructuring in the short to medium term is severely limited, and consequently the restructuring options are downplayed.

Performance

Eskom's post-1990 performance was until recently good by most measures: quality and security of supply were improving, rapid progress was made in extending access to electricity, the utility's debt was reduced and it commanded an excellent credit rating. Coal costs were very competitive by international standards. In recent years, however, quality of supply has deteriorated as ageing plant is run to the maximum; and security of supply has been prejudiced by delays in investment planning and ordering, partly caused by indecision over industry restructuring. The potential of demand-side management has started to be realised. Security of supply is likely to be tight over the next five years or more, even with Eskom's ambitious investment programmes. Delays in committing to independent power producers may further prejudice security. Planning and investment approval remains divided among too many different bodies.

While prices have been very low by international standards, the cost of new power – the long-run marginal cost (LRMC) – is considerably above price, leading to excessive electricity consumption and exacerbating the capacity shortage. Eskom's balance sheet presents asset values at written-down historic cost and, as a result, appears to significantly undervalue all the main asset classes. By this standard, existing prices appear to represent an appropriate rate of return. A more realistic asset valuation would demonstrate that the current rate of return is far too low, and prices are also too low. Prices will need to rise significantly to pay for the cost of new power. Present tariffs also fail to properly reflect marginal costs by time and region, so marginal prices (particularly at the peak) should, in any case, be raised as a matter of urgency to underpin any proposed demand-side management approaches and to discourage inefficient investment in energy-intensive industries.

Principal challenges

South Africa's electricity-supply industry faces seven principal challenges.

1) There is an urgent need for capacity expansion. Investment demands are high, costly and pressing. Security of supply has been compromised. The pressures on capacity have been

caused not so much by economic growth rates as by delays in reforms and unclear lines of authority and decision-making. The reform process has stalled to the point that radical reform would now probably do more damage than good (in terms of costs and disruption), given the extreme stresses upon the electricity system and its need for substantial "new build" and refurbishment. Nevertheless, a number of adjustments and improvements need to be made to capacity-planning processes, the system for allocating new-build opportunities (to Eskom or the private sector), and procurement and contracting mechanisms.

2) Policy-makers should try to ensure that Eskom's investment programme is done at the least cost and will be undertaken efficiently. There are several issues here. One is that state-owned enterprises typically suffer from soft budget constraints (they can expect the state to step in with loans or higher prices if insolvency looms). As a result, state-owned enterprises are under less pressure to cut costs than if they were subject to the private-sector discipline of takeovers and bankruptcy. Another issue is that investment planning expertise and information is concentrated in Eskom, a directly interested participant in potential competition with independent power producers and import power-purchase agreements. The National Energy Regulator of South Africa (NERSA) and the Department of Minerals and Energy (DME) suffer from asymmetric information, a lack of expertise and unclear responsibilities. The regulator has the merit of independence and impartiality, and can contract for expertise, but is in a weak informational position relative to Eskom – a problem that is exacerbated by the urgency of investment decision-making.

3) Eskom has been unable to keep its existing plant operating at adequate levels of reliability. Recent blackouts are not only a result of inadequate generation capacity. There have also been unprecedented breakdowns and failures in generation plant. There is a need for reviewing Eskom's management, its primary energy procurement strategies and its maintenance and operation systems.

4) There is a need to implement the pricing principles of efficiency and cost-reflectivity, and the principle of transparency in any subsidy programmes. These principles have been accepted by government and the regulator, but have not been systematically put into effect. The problem is that, as a state-owned enterprise, Eskom is subject to a particular price regime. Its prices are regulated at average cost based on historic book-valued assets, a low weighted average cost of capital and, at times, a waiver on dividend payments. If prices were to be raised to efficient levels (at least to long-run marginal costs, and sufficiently high to be acceptable to new independent power producers), then some of the pressure on capacity would ease in the short run. In the medium term the need for additional capacity would also be reduced – the amount of such a reduction would depend on the strength of the demand response to, among other factors, the new prices.

Setting efficient price levels would also have profound implications for industrial policy. Present low prices send incorrect signals to those engaged in energy-intensive investment, particularly when efficient or scarcity prices are likely to considerably exceed the LRMC for the next few years. Nevertheless, new energy-intensive industries have been encouraged, in recent years, with favourable long-term contracts offered at prices below the already under-priced tariffs and far below efficient prices. Setting prices at more efficient levels would not necessarily prejudice South Africa's comparative advantage in most energy-intensive industries.

The management of required price increases would create new challenges for governance and oversight. Efficient prices would dramatically increase cash flow. The money would reduce the scale of extra debt needed to finance expansion, but would also reduce the tightness of the budget constraints that Eskom faces, unless its owner (government), insists on large dividend payments. Managing large dividends puts strain on civil service bureaucracies, and would need careful administration.

5) Transmission constraints are a problem and transmission performance (measured in terms of major interruptions) has deteriorated. The cause is a combination of specific maintenance problems and inappropriate investment criteria applied in the past.

6) Distribution performance by municipalities is generally poor and could deteriorate further, at great economic cost. About half of South Africa's electricity distribution is delegated to municipalities, which lack appropriate, politically-insulated commercial structures for the management of distribution and supply, and which, in many cases, have failed to maintain infrastructure and retain suitably skilled staff. The establishment of regional electricity distributors (REDs) is stalled by constitutional and other legal objections. Various key decisions on national electricity-pricing policy, local government surcharges and the ownership and control of the regional electricity distributors remain to be resolved, while the actual merger of Eskom with municipal distribution management, staff, assets and systems has yet to begin.

7) Present data used for electrification planning probably overstates the numbers of households with access to electricity. At the same time, the costs of new rural connections are increasing rapidly. Universal access is unlikely to be achieved by 2012 at present connection rates. A new, more realistic policy should be developed that maps out the costs and benefits of expanding access.

8) South Africa's emissions of air pollutants and CO_2 are high and growing due to high energy-intensity and the large part that coal plays in generation. Whether it is cost-effective to reduce the carbon-intensity of electricity generation depends on the future price of carbon. Nuclear power appears uncompetitive against coal at present costs of capital and carbon prices.

Eskom's role

The challenges facing Eskom arise partly as a result of the utility's structural and institutional nature. Eskom can be usefully considered in terms of its historical goals, its financial position, its market position and its approach to reform.

In the 1970s and 1980s Eskom over-invested in capacity, regardless of the high cost involved. The current accelerated generation expansion programme runs a similar risk. A strong determination to ensure adequate capacity has its virtues – and there is no doubt that the costs of shortage can be much higher than the costs of excess capacity – but it also needs to be understood that the ownership and governance structure is geared towards overinvestment rather than underinvestment. The move to negotiate goals with government is a welcome step towards imposing a more efficient approach to investment and management, but requires a degree of commitment and expertise on the side of the shareholder that is demanding.

Financially, the state is not acting commercially as it fails to require Eskom to make an appropriate rate of return, and is effectively underwriting all risks without adequate recompense or risk mitigation (although, admittedly, it has the option of passing on the costs to customers rather than to taxpayers). A relatively low cost of capital – borrowing at favourable rates and funding out of retained profits that are not subject to competitive pressure – makes capital-intensive projects such as pumped storage and nuclear power appear relatively less costly (and hence more attractive).

The consequences of these systemic factors (and post-oil shock inflation) were cheap (in real terms) borrowing and over-investment in the 1970s and 1980s. The resulting substantial excess capacity turned Eskom into a cash cow. In the bargain between the state as owner and the utility's management, Eskom's favourable financial position in previous years made it possible to combine the state's desire for low electricity prices with Eskom's desire to secure strong political and commercial support from energy-intensive industries and low-income urban and rural consumers.

Eskom's commitment to deliver low-priced electricity to major users in energy-intensive industries considered responsible for the country's past economic success leaves government vulnerable should it propose a radical shift in policy. In fact, until recently government appeared to remain enthusiastic about an industrial strategy that relied on a continued capacity to generate large volumes of power from cheap coal, as was reflected in the government-mandated development tariff for energy-intensive users. However, the development strategy needs serious reconsideration, as very cheap fuel is only part of the cost of electricity – the overwhelming share of which is the very capital-intensive investment now required. Higher electricity prices encouraging less consumption would release funds to help stimulate other areas where South Africa is lagging.

The electrification programme undertaken by Eskom, starting in 1994, won wide political support and placed it in a favourable light, in contrast to many poorly performing municipal electricity undertakings. In the 1990s surpluses were used not only to fund electrification but also to under-price wholesale power – a strategy supported by the Department of Public Enterprises (DPE) without any strong intervention from National Treasury.[1]

The lack of cash constraints and availability of cheap finance might also have encouraged the utility's dalliance with nuclear power, a relatively costly energy source compared to local coal-fired generation. However, pressurised water nuclear reactors are one thing, and advanced research, development and construction of a very expensive pebble modular reactor are quite another. South Africa would seem to have no prior comparative advantage to support the creation of such an energy source.

State ownership and accounting, with its tendency not to act as a demanding shareholder requiring a reasonable dividend, combined with historic cost-accounting (that undervalues assets), a failure to charge an appropriate cost of capital (which, for historic cost accounting, should be a risk-adjusted nominal rate) and outdated (low) estimates of revenue requirements leads to under-pricing as demand tightens. Faced with an acceleration in demand growth and (until recently) a strong financial balance sheet, Eskom was well placed to go to the local capital market, potentially placing it under strain and possibly crowding out other investments (although it was also well placed to borrow abroad).

[1] In recent years, electrification has been funded from capital grants from National Treasury.

In terms of market position, Eskom, as the dominant vertically integrated incumbent, is well placed to see off any threats to restructure the market. It can easily undermine imports and the entry of independent power producers. Eskom can plausibly argue that independent power producers will demand higher returns, to compensate for market risks. It can also argue that reliance on imports might raise security-of-supply issues that need to be addressed at the political level.

It has been argued that it is in Eskom's interest, as a state-owned enterprise, to delay progress with reforms, resist structural change and attempt to keep control over the investment programme. Eskom vehemently denies this and says that it has actively cooperated in each reform step. It is likely that Eskom management has had mixed views about the creation of a competitive wholesale market and what this would have meant for the utility in terms of its industry and financial position. Given the costs of new power generation and the returns required by the private sector on investment, the creation of such a market would have pushed prices well above their current tariffs, offering Eskom the prospect of a considerable profit increase, and, consequently, the ability to expand at home and abroad. However, Eskom would also have faced the prospect of losing control over the industry, and strong political/shareholder pressure to hold down its prices, distorting the market.

Conflict over who controls future investment and distractions over where to take the reform agenda have arguably contributed to the pending security-of-supply crisis. At this late stage, the range of reform options has contracted; major reforms should probably wait until supply-security is restored, which could take at least a decade given the lengthy period required to build new coal-fired power plants. Nevertheless, a number of useful and important interim reforms should be made.

Restructuring options

Proposals for further restructuring of the generation and transmission business mainly are based on the introduction of private-sector participation. The policy of allowing independent power producers appears to have been accepted. Ideally, Eskom's generation assets should be unbundled from the system-operator function to avoid conflicts of interest.

The natural model here is of a transmission system operator and owner acting as the single buyer. The single-buyer office would hold Eskom's financial assets, planning capability, financing operations and most head-office functions. The generation assets would be spun off and the office would own the remaining ones, (although the distribution assets should also be spun off at a later date). Power stations would then hold power-purchase agreements (PPAs) with the single buyer, designed to ensure efficient dispatch decisions. Pumped storage could remain with the single buyer, which would also need to contract for other ancillary services. This model has a number of attractions. In particular, it should ensure fair dealing between independent power producers and Eskom generation stations, and in the process encourage a more timely and lower-cost supply of private participants.

There are some potential risks – if it alters the balance of bargaining power between coalfield owners and potential coal-fired generation companies – and it may delay the process for committing investment. Government has indicated that no major restructuring of Eskom will be contemplated until security of supply is restored and that the single-buyer function will be located in Eskom in the short to medium term.

Another option that has been shelved for the time being is further unbundling of the generation assets into a reasonable number of companies supplying a competitive wholesale market. The option requires private-sector acquisition of the generation assets (although the grid could remain in public ownership). The sales value of these assets would depend on the future market-price of electricity. In tight markets (such as South Africa's will be for the next five or more years) competitive prices would rise above the entry price (the long-run marginal costs) unless generators held medium-term PPAs at below market-clearing prices. Medium-run contracts are desirable in any privatisation since they offer future security. However, once this model depends on medium-term contracts it starts to move very close to the single-buyer model described above, while offering few clear advantages. The single-buyer model offers a transition to a genuinely competitive wholesale model – a transition that enables a build-up of adequate reserves and retail prices finally set at long-run marginal costs (the cost of new power generation). Such a transition is unlikely to be completed before 2013-15.

The most pressing restructuring challenge is clearly that posed by the distribution sector. Current plans to merge municipal and Eskom distributors into six REDs appear to be making little progress and will probably only be realised when the Constitution is changed to remove municipal authority over electricity reticulation. To minimise institutional disruption and potential threats to security of supply, the REDs should be anchored in Eskom's six distribution regions and full use should be made of the superior systems and project management capabilities of Eskom's regional offices. However, the municipalities are reluctant to transfer their distribution businesses into REDs that have a strong Eskom involvement and the recent Electricity Regulation Amendment Bill strengthens their position by making clear that the Constitutional reference to electricity reticulation refers to *all* distribution and retail functions.

Should progress towards the establishment of REDS continue to be frustrated, it is recommended that consideration be given to an alternative approach of abandoning this model and instead building on the support of the major stakeholders in the sector. It is proposed that the 12 largest municipalities, which together account for 80 percent of municipal electricity sales, should be allowed to retain their electricity businesses, but with intensive support to ensure that they are corporatised and effectively resourced. The large municipalities would take over Eskom distribution networks and systems within their municipal boundaries. Eskom would continue to be responsible for rural electrification, as well as large customers. Medium-sized municipal distributors that are performing adequately would be left alone, but those that are failing would be given incentives to transfer either to Eskom or to neighbouring municipal distributors. The model would cause relatively little disruption as it is built around existing major distributors.

It should be noted that security of supply is a major concern nationally and any moves to restructure the industry have to be carefully planned, should have the support and full participation of the major distributors, and should not disrupt institutional capacity to deliver electricity services.

Recommendations

The report's key recommendations, presented in Section 5, are summarised below.

Electricity policy

A new electricity sector policy should be developed. It should address sector goals, supply security, planning, private-sector participation, investment decision-making and approvals, procurement, co-generation and renewable energy, energy efficiency and demand-side management, environmental issues, electrification, distribution restructuring, pricing, regulation and financing.

Electricity security, generation planning and investment

- A commission of inquiry should be established to determine the root causes of the current electricity shortages as well as the performance of Eskom's management in restoring electricity supply security. Based on the evidence before the commission, required management and operational changes should be implemented.

- An electricity security of supply standard should be established by the Minister of Minerals and Energy in consultation with the DPE, Eskom and NERSA. The system operator should be charged with the responsibility of reporting and publishing actual performance against this security standard. NERSA should be responsible for monitoring security of supply and recommending early remedial action when necessary.

- Electricity planning should be coordinated and integrated by consolidating and transferring all planning activities (including those currently undertaken by NERSA) into Eskom's new system operator and planning division. This would help to eliminate confusion and contradiction. A suitable governance arrangement should be established that would allow adequate inputs by all key stakeholders. National electricity plans and investment opportunities should be published on an annual basis.

- The process of allocating new generation capacity opportunities to either Eskom or the private sector should be transparent, clear and rational. Investment approval and licensing for such capacity should be streamlined.

- Procurement of new private-generation capacity in the form of independent power producers with off-take agreements with Eskom should be made more efficient. The process should be conducted through a new single-buyer office, situated initially in Eskom and overseen by NERSA, DPE, DME and National Treasury.

- The regulator and the DME should facilitate efforts to obtain economic off-take agreements for co-generation plant, renewable energy and for unsolicited energy supplies offered by independent power producers (up to an agreed maximum capacity) and should fast-track licensing approvals for such plant.

- The Department of Minerals and Energy, in consultation with NERSA and Eskom, should establish a prudent maximum electricity-import percentage.

- Once supply security has been established, consideration should be given to separating Eskom generation plant from the transmission and system operator, and associated planning and single-buyer functions. Eskom would become the single-buyer, and generation plant (ex Eskom and independent power producers) would be contracted on medium-term PPAs (leaving open the future option of establishing a wholesale market).

Transmission

- The business case requirements in the grid code for an "N-1" transmission reinforcement should be reviewed so that that the necessary investments are made to ensure adequate transmission infrastructure.

Distribution

- The highest priority should be given to ironing out policy uncertainties concerning the rationalisation of the electricity distribution industry and providing a clear road map.

- If the REDS model is selected, then the six distributors should be anchored in Eskom's six distribution regions to minimise institutional disruptions and to capitalise on Eskom's superior systems and project management capability.

- If problems in implementing the above model become insurmountable, an alternative should be considered. In this model, the 12 largest municipalities should be allowed to keep their electricity businesses and intensive support should be provided to strengthen their governance, management, accounting and investment in assets and people. Well-performing medium-sized municipal electricity distributors should also be allowed to continue operating. Eskom would continue to be responsible mainly for rural customers and also large contestable customers. Small municipal distributors should be transferred either into Eskom or larger municipal distributors.

Environmental issues

Given its low cost, any decision to diversify away from coal should be considered very carefully, based on a realistic and preferably contracted long-term price of carbon. It is understood that Eskom now applies a shadow value to carbon. This does not, however, feed through to cash flow, and fails to create properly costed disincentives to carbon-intensive energy.

Pricing and regulation

- Government should formulate a policy that empowers the regulator to award the kind of revenue levels to Eskom that would foster a migration of prices to long-run marginal costs (LRMCs) and tariffs that reflect scarcity prices at the margin. Average base-load prices would need to move towards at least the LRMC in relation to generation, even if transmission and distribution were priced at average cost. Peak-load prices should reflect the very high cost of generation and marginal transmission losses (twice the average), as well as long-run marginal capacity costs. Off-peak prices would exclude capacity costs.

- NERSA should allow the required revenue that would enable Eskom to pursue cost-effective demand-side management programmes, supported by tariffs that reflect scarcity prices.

- Eskom should not offer new long-term contracts to large users at less than the LRMC, and should not accept new large supply commitments that prejudice security of supply. In effect this may mean that new contracts can be interrupted.

- Average revenue per kWh for existing customers can evolve more gradually towards the LRMC. Price increases over the period to 2012, combined perhaps with a revaluation of Eskom's assets, would ease the debt-equity constraint somewhat, although other vital financial indicators would also need to be tracked.

- NERSA should encourage Eskom to move towards greater regional differentiation of electricity prices.

- The Electricity Regulation Act should be amended to make retail choice possible for large customers.

- The regulatory process should be streamlined by eliminating parallel approval processes and clarifying the regulator's tariff-setting powers over municipal electricity reticulation.

Electrification

- There is little chance of universal access being achieved by 2012 at current connection rates. A new, more realistic policy should be developed that maps out the costs and benefits of expanding access and assigns pragmatic targets with required funding and clear accountability.

2. INTRODUCTION

The South African government recognises the importance of infrastructure in underpinning and facilitating economic growth as well as improving social welfare. Capital investment in the area is expanding rapidly. However, concerns have been expressed about the scale, timing and efficiency of the investments as well as the efficiency of infrastructure operations.

This paper assesses the performance of the electricity sector in South Africa by examining prices and costs, the quality and security of supply, operating efficiencies, capacity and investment planning, financing, electrification and environmental impacts. The primary focus is on Eskom because of its dominant position in the sector. However, the performance of municipal electricity distributors is also examined in those areas where relevant data is available. Eskom's performance is benchmarked, where appropriate, against international utilities.

Key problems, issues and challenges are diagnosed. A number of recommendations are made to address institutional and regulatory challenges.

Overview of the structure of the South African electricity supply industry

South Africa's electricity supply industry remains dominated by the state-owned and vertically integrated utility, Eskom, which ranks seventh in the world in terms of electricity sales. Eskom generates 96 percent of the country's electricity, which amounts to more than seventy per cent of the electricity generated in Sub-Saharan Africa. Private generators contribute about 3 percent of national output (mostly for their own consumption) and municipalities contribute less than 1 percent. The electricity infrastructure is heavily dependent on coal (92 percent) with nuclear, hydro-electricity, bagasse (from sugarcane) and emergency gas turbines accounting for the rest.[2]

Eskom owns and controls the national integrated high-voltage transmission grid and distributes about 60 percent of electricity directly to customers. The remaining electricity distribution is undertaken by about 185 local authorities that buy bulk supplies of electricity from Eskom.

Eskom also imports power from Mozambique, and to a lesser extent from the Democratic Republic of Congo and Zambia. It also sells electricity to neighbouring countries (Botswana, Lesotho, Mozambique, Namibia, Swaziland, Zambia and Zimbabwe). Imports and exports constitute about 5 percent of total electricity on the Eskom system. Eskom's power stations are listed in Figure 1.

[2] Eskom Annual Report 2006; National Electricity Regulator – Electricity Supply Statistics for South Africa 2004.

Figure 1: Eskom's power stations[3]

Name	Location	Fuel	Available MW
Arnot	Middelburg	Coal	1V980
Camden	Ermelo	Coal	(1 520) 760
Duvha	Witbank	Coal	3 450
Grootvlei	Balfour	Coal	(1 200)
Hendrina	Hendrina	Coal	1 895
Kendal	Witbank	Coal	3 840
Komati	Middelburg	Coal	(1 000)
Kriel	Bethal	Coal	2 850
Lethabo	Sasolburg	Coal	3 558
Majuba	Volksrust	Coal	3 843
Matimba	Lephalale	Coal	3 690
Matla	Bethal	Coal	3 450
Tutuka	Standerton	Coal	3 510
Acacia	Cape Town	Gas/petroleum	171
Port Rex	East London	Gas/petroleum	171
Gariep	Orange River	Hydro	360
Vanderkloof	Orange River	Hydro	240
Drakensberg	Bergville	Pumped storage	1 000
Palmiet	Grabouw	Pumped storage	400
Koeberg	Cape Town	Nuclear	1 800
TOTAL			**36968**

Source: Eskom *Annual Report 2006* plus latest information on Camden
(Bracketed data reflects previously mothballed capacity)

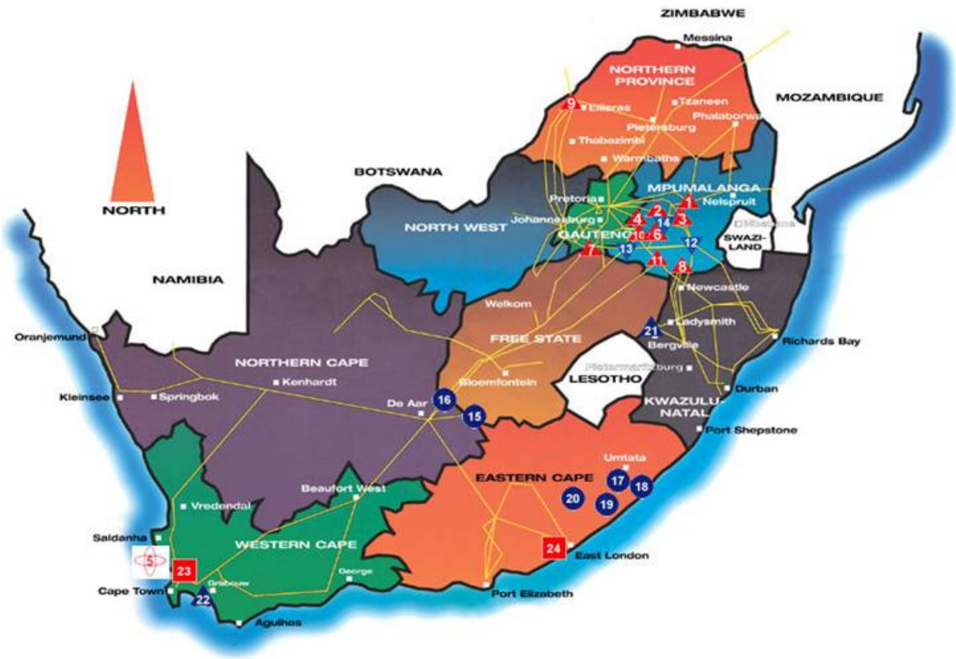
Direct electricity sales to mines and industrial customers accounted for more than 40 percent of Eskom's electricity sales in 2005/06. Eskom also operates retail distribution services for 3.75 million customers (3.6 million of these are to households) and the municipal distributors service an additional 4 million customers. About two-thirds of South Africans have access to electricity.[4]

South Africa's electricity ranks among the cheapest in the world. Eskom's average electricity price in 2005/06 was R0.17/kWh (US$0.02/kWh). Average industrial tariffs were R0.14/kWh and household tariffs were R0.40/kWh.

South Africa's electricity supply system is shown in Figure 2. Eleven of Eskom's 13 coal-fired power stations are located in Mpumalanga province in the northeast; the other two are at Lephalale in Limpopo province and at Sasolburg. The two major hydro stations are located on the Orange River in the centre of the country. Eskom's Koeberg nuclear power station is located 30km north of Cape Town. The gas (kerosene) turbines are on the coast. These are small and are used for emergency peaking loads only. Peak demand is also supplied by pumped storage schemes in the Cape and in the Drakensberg mountains in KwaZulu-Natal. The South African power system is thus characterised by power stations that are concentrated in the interior near the mines and industries of Gauteng and Johannesburg, and long transmission lines down to coastal areas, which depend on power transfers.

[3] Figure excludes four small, non-operating hydro plants in Transkei. The balance of non-Eskom generating capacity totals about 1 400MW and is located mainly at Sasol's synfuels plant (520MW), Kelvin (280MW), Rooival (258MW) , Pretoria West (50MW), Steenbras (180MW) and Tongaat-Hulett (<100MW).
[4] Eskom Annual Report 2006; National Electricity Regulator – Electricity Supply Statistics for South Africa 2004.

Figure 2: South African electricity supply system



Policy framework

Eskom is governed through a shareholder compact with the DPE. However, overall energy and electricity policy is the domain of the Department of Minerals and Energy. Formal policy for the electricity sector was recorded in the White Paper on Energy Policy published in 1998. Electricity-supply industry objectives were proposed. These were to:

- Improve social equity by specifically addressing the energy requirements of the poor
- Enhance the efficiency and competitiveness of the economy by providing low-cost and high quality energy inputs to industrial, mining and other sectors
- Achieve environmental sustainability in both the short- and long-term usage of natural resources. [5]

The White Paper also envisaged giving customers the right to choose their electricity supplier; introducing competition, especially in the generation sector; permitting open, non-discriminatory access to the transmission system; and encouraging private-sector participation.[6] It also stated that the distribution sector would be consolidated into "the maximum number of financially viable independent regional electricity distributors". In the long term, Eskom would "be restructured into separate generation and transmission companies". Government intended to separate power stations into a number of companies to introduce competition. Independent power producers would be introduced.[7]

The policies were confirmed by Cabinet in May 2001 and government engaged consultants to design an electricity market, which would include a power exchange. While distribution and

[5] Department of Minerals and Energy (1998). White Paper on Energy Policy for South Africa. Pretoria, p29.
[6] Ibid, p29.

[7] Ibid, p32,43-44.

transmission were to be unbundled, Cabinet stopped short of full horizontal unbundling of Eskom's generation plant: only 30 percent was to be sold and the rest was to be clustered into a number of competing generation units. In the meantime, Eskom was prohibited from building new generating plant and was encouraged to expand its activities into the rest of Africa.

The electricity market, however, was never implemented, and in 2004 Cabinet announced that Eskom would not be unbundled, nor would it be privatised. Work on the design of the electricity market was terminated and Eskom was once again authorised to invest in new capacity, while independent power producers would be invited to contribute up to 30 percent of new generation capacity. A revised electricity policy has not formally been published. However, it is now clear that the electricity policies in the 1998 Energy Policy White Paper no longer apply, even though the paper has not been formally withdrawn. Government sees Eskom as a "national champion" that will spearhead infrastructure investment in support of economic growth and improved welfare. Government ministers have said that Eskom's generation and transmission divisions will not be unbundled and that Eskom needs to take primary responsibility for security of electricity supply.

The May 2001 Cabinet decision also confirmed that Eskom and municipal distributors would be consolidated into six regional electricity distributors (REDs). In 2005/06 a different restructuring model was briefly considered that envisaged six metro REDs with Eskom being responsible for a "national RED" and other municipal distributors migrating over time to either the metro REDs or Eskom. However, in October 2006, Cabinet reaffirmed its commitment to establish six REDs that would cover the entire country. However, no concrete progress has been made in establishing the REDs. The first such distributor was disbanded after neither the City of Cape Town nor Eskom transferred their local assets and staff into the entity by the stipulated deadlines.

Other formal, published policies that affect the electricity sector include a 2003 White Paper on Renewable Energy, which established a modest target of 10 000GWh by 2013.[8] Policy documents have also been published by the DME on energy efficiency, electrification and a "basic electricity tariff" that specifies that certain targeted households should be eligible for 50kWh per month free.

The legislation governing the electricity sector (see Appendix 1) stipulates in some detail how Eskom or municipal distributors should be governed and how they should account to government. It specifies also how the industry should be regulated: it empowers the Minister of Minerals and Energy to procure and contract independent power producers and to direct the regulator to licence specific plant, including the proportion that should come from renewable energy sources.

Government has also directed that poor households should receive electricity subsidies. While subject to environmental legislation, generating plant is not required to meet European or North American emission standards. There are no greenhouse-gas emission caps. New legislation is currently being drafted that will define the process for restructuring the electricity distribution industry.

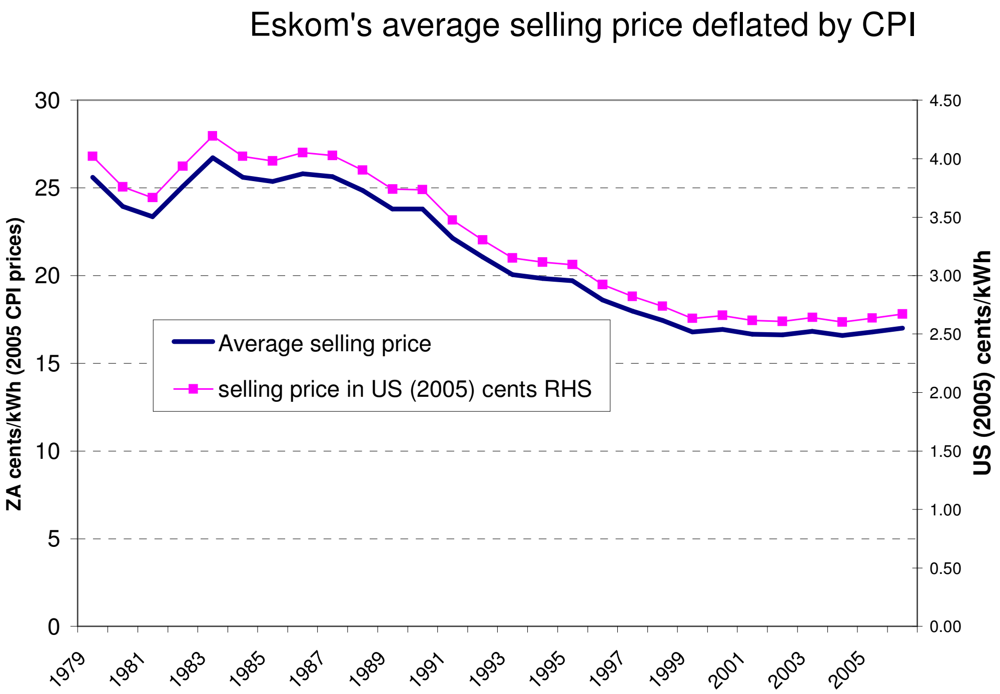
[8] This is roughly equivalent to 4 percent of projected electricity demand in 2013. There has been some confusion over the precise meaning of this target and some officials have interpreted it to mean 10 000 cumulative GWh of renewable energy in the period up to 2013, or as encompassing all renewable energy production, not just renewably produced electricity.

3. ELECTRICITY SECTOR PERFORMANCE

Prices and costs

Eskom's prices are very low by international standards and have been decreasing in real terms, as Figure 3 shows.[9]

Figure 3: Average real sales price of Eskom's electricity, 1979-2006



However, a low price does not necessarily indicate a low cost, and here the calculations are rather more complex. Electricity is a highly capital-intensive industry, where the variable costs can be a small fraction of the average total costs. The average total cost will depend sensitively on the cost of capital. The variable cost is primarily driven by the cost of fuel. The efficient price should be set equal to the relevant economic cost, which will depend on the state of demand relative to supply. If there is spare capacity (off-peak, or in periods of high reserve margins), then the relevant cost is the short-run marginal cost, which will be close to the variable element in the fuel cost of the marginal plant.[10] If demand is tight (at the peak and/or when reserve margins are low), the short-run marginal cost will be higher (and perhaps much higher) but capacity also has a scarcity price, which can be very high if the high capital cost of extra plant required to generate the extra power is attributed to the small number of hours when the capacity constraint is binding.

[9] The South African series are deflated by the CPI to 2005 prices, and the US$ price is found by converting this at the average 2005 US$/R exchange rate and is read on the right hand side – they would be coincident if the exchange rate were R6.66 instead of the actual R6.37/$.

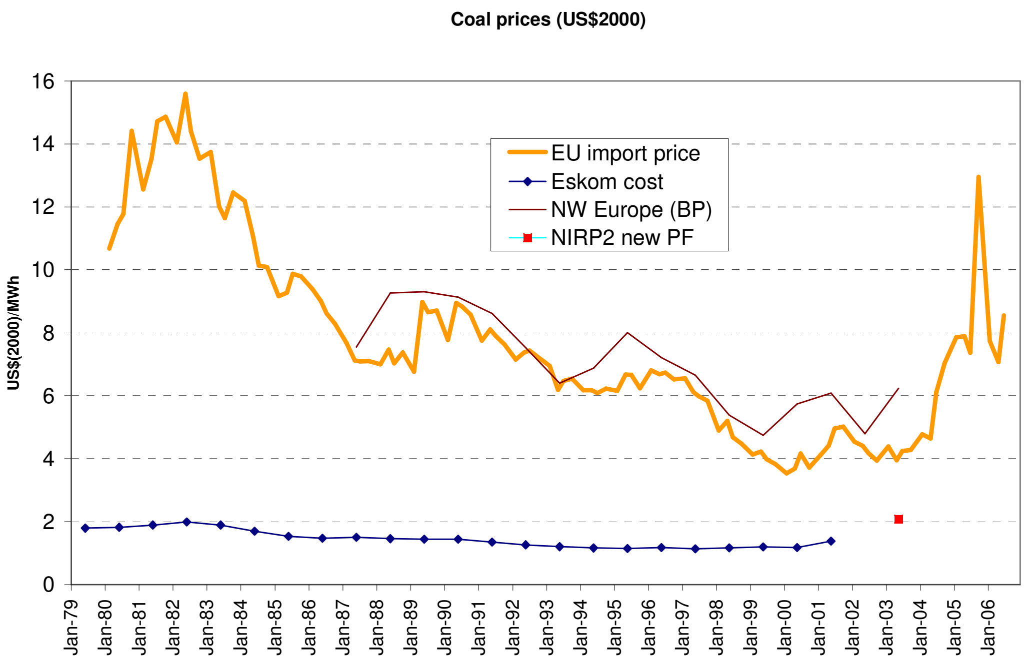
[10] Other variable costs such as operations-and-management and wear-and-tear can also be material for some plant and should be included.

At some point the scarcity price during the hours of tight demand will justify investment in new capacity, and the relevant cost then becomes the LRMC. Base-load electricity will then have to pay the levelised capital cost of new base-load plant, but peak power prices will be considerably higher, since, although the peaking plant may be cheaper per kW capacity, it will run only a small number of hours each year. The capital charge averaged over these hours can therefore be very high. These elements will give the ex-station cost of power, but to deliver it to consumers requires transmission and distribution assets that together make up more than half Eskom's accounting capital cost and about one-third of the allowed revenue set by NERSA, making the retail price 150 percent of the generation cost. Again, efficient pricing of the transmission and distribution assets would attribute them primarily to peak demand hours, although losses should be attributed to the time incurred (and allocated where marginal losses are caused).

Generation costs

Eskom's generation is overwhelmingly (92 percent) from large coal-fired plant, and South Africa is endowed with abundant low-cost coal.

Figure 4: Eskom's coal costs compared to those for northwest Europe



Sources: BP *Statistical Review*, IEA *Energy Prices and Taxes,* Eskom

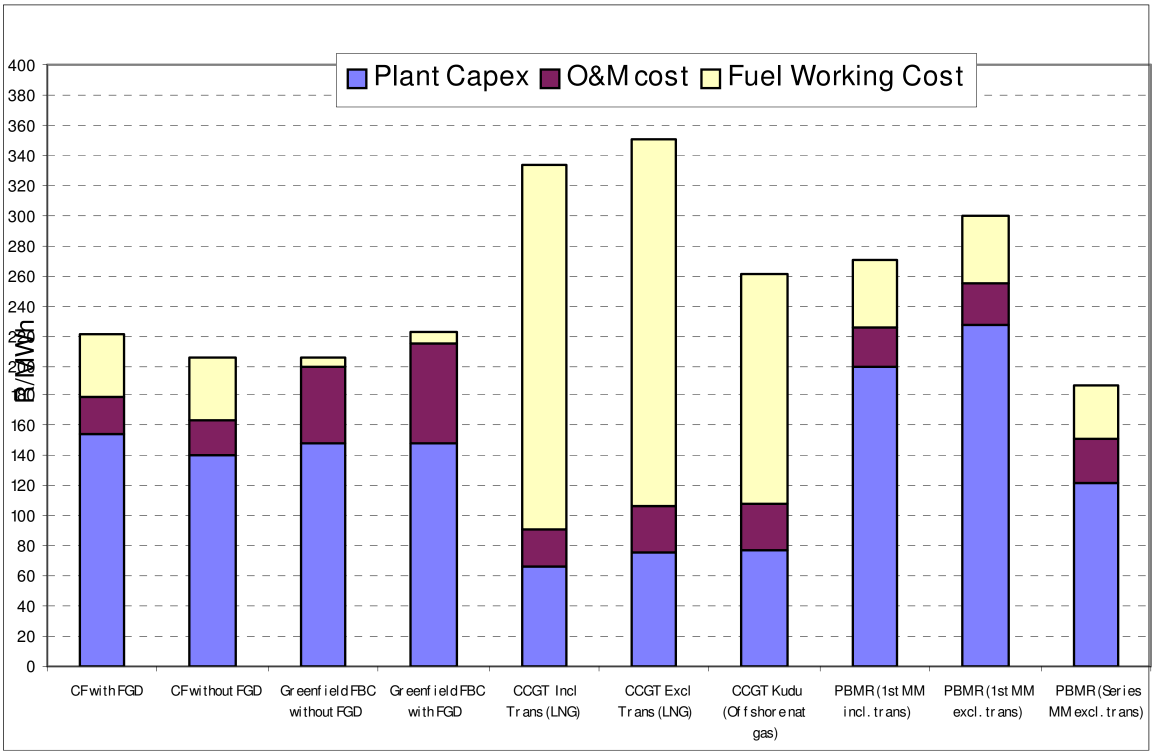
Historically, Eskom has enjoyed remarkably low coal prices, and this gives coal-fired generation a major cost advantage compared to other fuels. Figure **4** shows the evolution of coal costs (in US$/MWh of the energy content of coal, not of the cost of generating electricity)[11] for Eskom and for coal delivered into north-west Europe (on top of which there would be delivery costs to power stations). Although international coal prices were decreasing in real terms until 2004, by 2006 they had roughly doubled in price and have risen further since then. Even at their lowest, European coal prices were nearly three times

[11] The Eskom costs are first deflated to 2000 values and then converted at the 2000 exchange rate; the north-west Europe prices are deflated by the US CPI to 2000 values. The fuel cost of generating electricity is found by dividing by the thermal efficiency, which on average for Eskom was 34.4 percent in 2000. Hence the generation fuel cost is roughly three times the value shown on the graph.

Eskom's costs. The coal costs in the NERSA's National Integrated Resource Plan 2 (NIRP2) are roughly 50 percent above the historic average, and have increased since the plan was written, raising the long-run marginal cost of base-load power.

Appreciation of how low fuel costs are for coal-fired plant can also be gained by looking at fuel costs as a proportion of the average (or levelised) total cost of new power stations. Figure 5 is taken from NIRP2, which is now rather out of date, particularly as it relates to fuel costs (coal prices have risen sharply with the negotiation of new contracts). Nevertheless the fact remains that South Africa is a source of very cheap coal for power generation. Thus, for new small (446MW) plants operating FBC without FGD technology (fluidised bed combustion without flue gas desulphurisation) and burning low calorific value coal (14GJ/tonne), fuel costs were estimated at R7/MWhe on the basis of R0.75/mBTU. For large (3 900MW) new coal-fired stations burning higher calorific value coal (19.4GJ/t, comparable to high-quality steam coal of 24-26GJ/t), fuel costs rise to R41/MWhe.

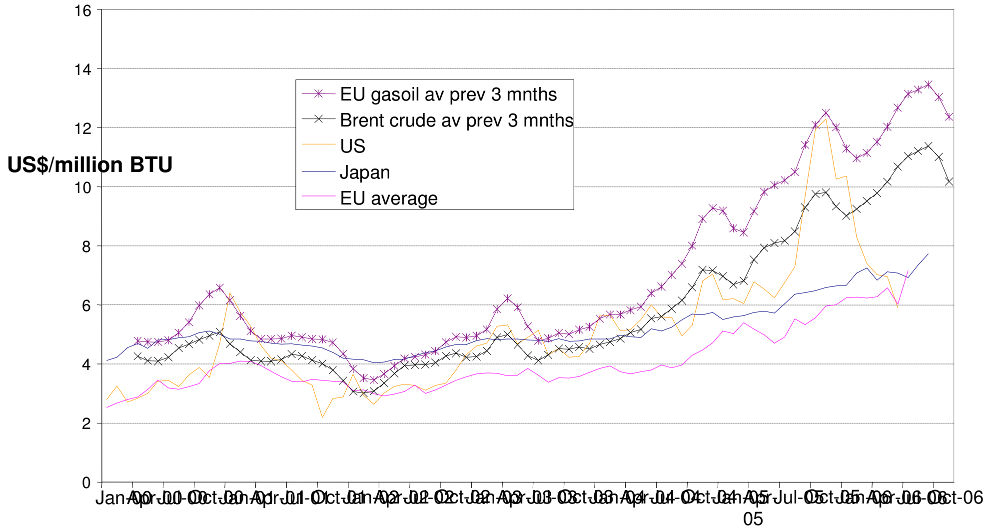
Figure 5: Comparative levelised costs from NIRP2 (2003 prices)



Note that gas-fired plant has very high fuel costs. Local (Kudu) offshore gas has fuel costs of R152/MWhe while liquefied natural gas (LNG) was estimated at R243/MWhe. The variable fuel cost from LNG is nearly six times as high as that from high calorific value coal, although the capital costs are less than half as high.

Since 2003, LNG prices have substantially increased, as Figure 6 shows. In early 2003 both US and EU LNG prices were about US$3.50/mBTU, but by 2006 they were nearly double that level. If this price were applied to the generation cost of LNG plant, the fuel costs alone would be, at March 2007 exchange rates, R410/MWhe. The graphs shows that gasoil (which is the natural alternative to gas for gas turbines used as peaking power) is on average 60 percent more expensive than LNG, and that the LNG price (at least in Europe) appears to lag the oil price by about three months.

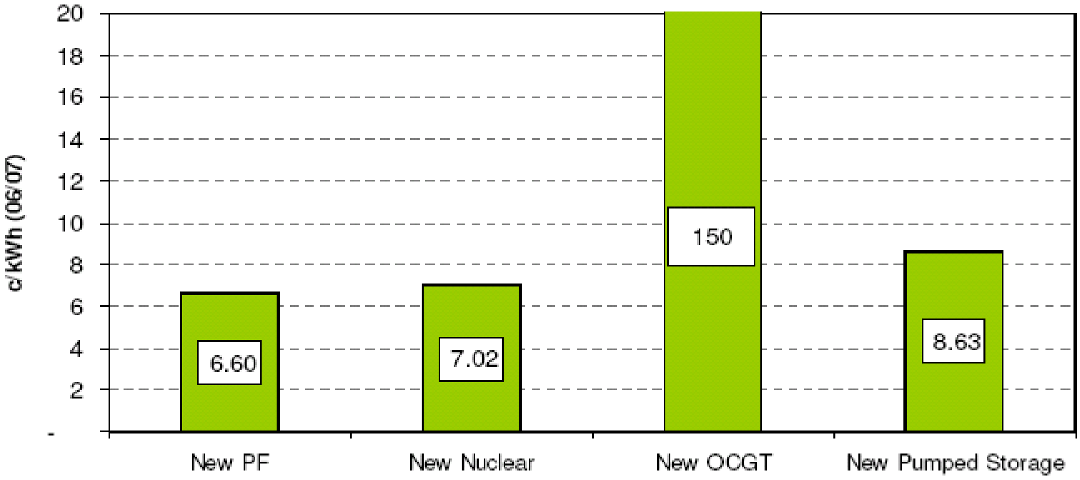
Figure 6: Liquefied natural gas and oil import prices



Source IEA *Energy Prices and Taxes*

As a result Eskom has revised its fuel cost estimates. Figure 7 from its *Forward Price Curve* (19 March 2007) shows that average coal costs have risen to R66/MWhe.[12] Coal costs are projected to rise 2 percent a year. (presumably in real terms) until 2036. Meanwhile, the open-cycle gas turbine cost of R1,500/MWhe confirms the impact of recent oil price rises. The fuel cost of new nuclear power has risen to R70/MWhe.

Figure 7: Estimated starting primary energy values for new supply options



Source Eskom *Forward Price Curve* 19 March 2007; figure includes all fuel, water, sorbent, transport, storage and handling charges, exchange rate R7.06=US$1

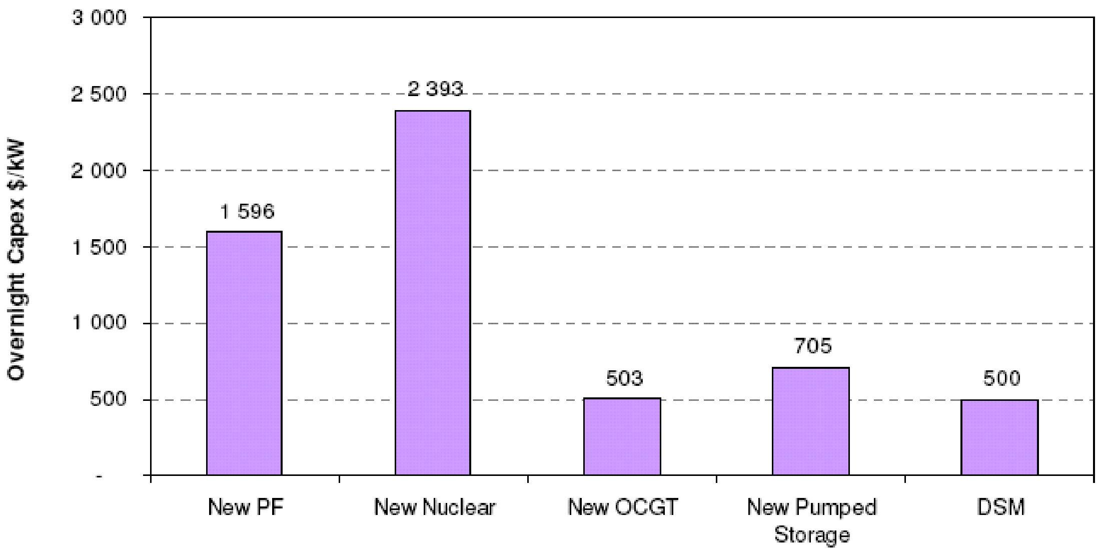
Eskom's estimates of capital costs for the different kinds of plant are shown in Figure 8. Capital costs for coal have risen 15 percent from earlier NIRP2 estimates (5 percent above the rate of inflation), making the capex cost R177/MWhe. However, it is clear that the recent

[12] Eskom now considers that R47/MWhe would be a low estimate for new coal PF station.

boom in coal-fired power station orders has increased costs by substantially more than 5 percent in real terms since 2003. According to a report by *Platts,* new-build power station costs have increased by as much as 30 percent since 2005, about half because of the rise in materials costs, and half from increasing margins after the depressed levels reached in 2004. The supplier market remains tight. The implications of all this are that timing construction projects becomes more critical and that capital costs might have been underestimated by perhaps 20-25 percent. That would raise the capex cost of generation to perhaps R215/MWhe.

If the cost of operations and management has not changed in real terms, the total unit cost would come to R177+R27+R66 = R270/MWhe on Eskom's 2007 figures, almost the same as that estimated for Matimba by Integrated Strategic Electricity Plan 10; or R320/MWhe, if the higher capital costs from tighter supply markets are factored in. New nuclear capex costs are calculated as R205/MWhe (presumably including the transmission benefit). If operations and maintenance came to R29/MWhe, this would give a total cost of R304/MWhe, 12 percent higher than the 2007 coal cost, and equivalent to a carbon price of US$7/tonne CO_2.[13] Recent evidence from the US (IHS Inc. and Cambridge Energy Research Associates)[14] suggests that if anything, nuclear construction costs have experience even higher cost inflation than coal-fired plant. As nuclear capital costs are more significant for the final cost of electricity than in coal-fired plant, a 30 percent increase would increase nuclear generation costs to R366/MWhe, 14 percent higher than the revised coal cost, and now requiring a carbon price of US$9/tonne CO_2.

Figure 8: Estimated capital costs of new supply options



Source: Eskom *Forward Price Curve* 19 March 2007

Carbon pricing

Eskom has high levels of carbon dioxide (CO_2) emissions. Carbon is now priced within the European Union and has been given a shadow price through an internationally agreed mechanism for reducing greenhouse gases (the Clean Development Mechanism). Eskom at present uses a shadow cost for CO_2 calculated as half that set by the EU emissions trading

13 This assumes that the new coal-fired power stations are super-critical with 700gm CO_2/kWh emissions.
14 http://energy.ihs.com/News/Press-Releases/2008/IHS-CERA-Power-Capital-Costs-Index.htm

system. Taking the second period price, this has varied between €15 and €25 per tonne of CO_2 in the year from June 2006. At 2007 exchange rates the price comes to US$28 per tonne of CO_2, suggesting an Eskom shadow price of US$14 per tonne of CO_2. Carbon price, of course, could affect the cost of future generation and the choice of fuels for new investment (and hence the LRMC). Eskom produces 0.978 tonnes CO_2 per MWhe of electricity. At US$10/tonne of CO_2 this adds US$9.8/MWhe or R66/MWhe to the cost of electricity using the present (mainly coal) form of generation. At US$14/tonne of CO_2 the cost of electricity rises by R92/MWhe. NIRP2 estimated coal fuel costs are R46/MWh at 2006 prices (and new coal prices are higher), so the shadow carbon price would likely more than double the cost of coal and raise the long-run marginal cost by 26 per cent or more.[15]

It would seem that the present costs of coal and those of assumed carbon shadow prices do not justify building super-critical coal-fired plant rather than sub-critical plant. Nevertheless, Eskom reports that for the next power station at Medupi, sub-critical and super-critical have very similar lifecycle costs (even without factoring in the shadow value of CO_2). On this basis, Eskom has therefore decided that all future plant will at a minimum be super-critical, perhaps reducing CO_2 emissions to 0.7 tonnes CO_2/MWe, which at $14/tonne of CO_2 the cost of electricity from new plant would rise by R70/MWhe.

Forward prices

Eskom's *Forward Price Curve* (19 March 2007) projects average unit costs rising in real terms from R0.18/kWh to R0.46/kWh in 2036, of which generation costs would more than treble from R0.12 to R0.37/kWh. The forecasted increase is partly due to rising real fuel costs (coal, at 2 percent a year, rises by 51 percent) but mostly due to the replacement of written-down historic-valued plant by properly accounted for new plant (where the capital cost is allocated over its lifetime at a steady rate). Transmission is forecast to rise from R0.017 to R0.024/kWh, distribution from R0.05 to R0.06/kWh – considerably less than a 50 percent increase, perhaps because the networks need less replacement. Past historic-cost accounting and the averaging of new and old costs would lead to prices rising at a modest pace in order to allow Eskom to earn a regulated real 6.5 percent pre-tax rate of return. Prices could rise from R0.18/kWh in 2006 to reach R0.46/kWh in 2036.

However, such calculations presuppose that Eskom would continue to reflect the written-down value of its current assets in prices. However, such may not be the case, as a more detailed examination of Eskom's accounts shows.

Eskom's financial performance

Eskom's *Annual Report* appears to show a quite satisfactory rate of return on assets.[16] Figure 9 shows a rate of return on total assets[17] above 10 percent for the most recent five years.

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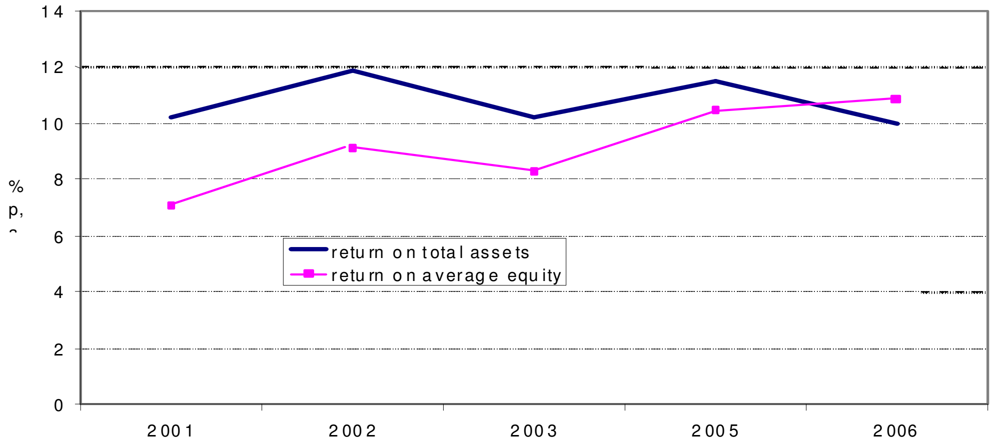
[15] One can undertake a back-of-the envelope calculation to see how much it is worth paying per kW capacity for a super-critical coal-fired plant (running at 38 percent efficiency) compared with a sub-critical plant (running at 35 percent efficiency). If coal+carbon costs are R120/MWhe at 35 percent efficiency, then they will be R110.50/MWhe at 38 percent efficiency. If plant life is 40 years, load factor 90 percent, and discount rate 10 percent, the saving in fuel costs is R75/kW/year, which gives a present value of about R750/kW, somewhat below the extra cost of super-critical plant, which might have a capital cost penalty as high as R1 100/kW, despite saving 8 percent of CO_2 emissions per kWh delivered. Without the carbon price the value of the higher efficiency would only be about R300kW.

[16] The *Annual Report 2007* does not provide rates of return below group level, where in the year to 2007 the return on total assets fell from 9.1 percent to 7.8 percent, although the return on average equity rose from 9.5 percent to 12.0 percent. This only partly reflects a rebasing of the financials, and is apparently mainly due to the

Figure 9: Reported rates of return from Eskom's accounts



Eskom's *Annual Report 2006* shows company fixed assets (property plant and equipment) as R63.7 billion, total assets as R124 billion and equity at R48 billion. Company profit before tax was R7.16 billion, suggesting that the rate of profit on total assets was closer to 6 percent than 10 percent. Further data include generation assets at cost of R51.3 billion and accumulated depreciation of R24.9 billion, giving a carrying value of R26.4 billion or 41 percent of total fixed assets. Transmission accounted for 11 percent, distribution 31 percent and works under construction 10 percent of total fixed assets.

The written-down values follow standard accounting conventions and fall far short of their economic value. In Eskom's *Annual Report 2003*, the accounts are also reported in inflation-adjusted terms. The historic-cost net profit after tax was R3.2 billion, but after inflation adjustments this fell to a loss of R2.9 billion. (The corresponding figures for 2002 were R3.2 billion net profit and a loss of R2 billion, inflation adjusted.) The inflation-adjusted asset value for the company shows the total assets in commission valued at R49.2 billion in 2003 at historic-cost value, but after adjusting for inflation the current value is shown as R108.9 billion at 2003 prices, or 221 percent of the historic-cost value. [18]

However, the written-down book values used in the Eskom annual reports tend to underestimate the real value of the utility's generation, transmission and distribution assets. Instead of writing down the assets at historic cost, their value to the business can be calculated in comparison with the costs of building and running new plant. Under such an optimal deprival value (ODV) calculation, the worth of existing plant and equipment soars – and consequently, the present rate of returns reported by the utility look relatively paltry (see Figure 10). The 2006 ODV net present value for present generation assets (coal-fired and

impact of the first year of the multi-year price determination, which Eskom fears might lead to even lower rates of return in 2008.

[17] Defined as net operating income expressed as a percentage of total assets, reduced by the amount of financial-market assets and interest receivable.

[18] In a helpful memo of 26 April, 2007, Eskom explained that the inflation-adjusted asset value "was based on indexing (using official SA statistical information) against inflation, from the original purchase date of the existing assets, according to the recommended accounting standards of the time. Bear in mind it was for accounting and reporting purposes, not economic or tariff setting purposes."

nuclear) comes to about R200 billion (or possibly more, as discussed in Appendix 2). This compares with a written down book-value at historic cost of R26.4 billion, as reported in March 2006. Appendix 2 presents an analysis of Eskom figures compared with ODV estimates.

An ODV estimate of Eskom's total assets in commission in 2006 (and at 2006 prices) gives a figure of about R335 billion. After depreciation and labour, the rate of return on the assets using the ODV calculation comes to only 1.8 percent. This return can be compared with a weighted average cost of capital (WACC) sought by electricity planners of 7.6 percent real (and a present allowed rate by the national regulator of 6.5 percent).

With regard to transmission assets the book value of R7.2 billion appears to be a substantial underestimate. An ODV value of R33 billion seems reasonable. However, since Eskom's reallocation of costs to the transmission network, the rate of return – in the form of average grid charges – might be considered defensible, although one could also defend a higher amount.

In relation to distribution, it would seem that a substantially higher regulatory asset value than R20 billion (their present written-down carrying value) could be justified, with a preferred estimate of R80 billion. After depreciation has been taken into account, distribution costs should rise by anything between zero and 16 percent.

Figure 10: Estimates of Eskom's 2006 asset values (R billion)

	CCA original cost 2003 at 2006 prices	CCA current value 2003 at 2006 prices	HC carrying value 2006 March	HCA depreciation	Estimated ODV	Depreciation on CCA cost	ODV/ CCA	ODV/ HC
Generation	197.6	76.5	26.4	2.2	**200**	4.9	***2.6***	7.6
Transmission	49.0	12.5	7.2	0.5	33	1.2	2.6	4.6
Distribution	78.1	31.4	19.7	1.5	80	2.0	2.5	4.1
Land and buildings	21.5	6.6	1.8	0.0	17	0.4	2.6	9.4
Other	8.4	1.9	1.9	0.4	5	0.6	2.6	2.6
Total in commission	354.6	128.9	57.0	4.6	335	9.1	2.6	5.9
Mothballed plant	15.6	3.9	0.0					
Work under construction	3.6	3.6	6.5					

Source: Eskom's accounts (2003, 2006) and calculations

Pricing policy

In 2003, National Treasury received a number of reports on administered (i.e. regulated) prices in various sectors. Two of them criticised the system of regulating electricity prices. Storer and Teljeur (2003) noted that: "To date, NER [the National Electricity Regulator] has not yet implemented a robust approach to regulating Eskom prices. Until recently this has not been a significant problem as Eskom prices were falling in real terms, however, the NER is currently grappling with the challenge of avoiding allowing Eskom excessive free cash flows, while ensuring adequate incentives (including prices) for the investment in new capacity. … Government has not found a definite solution to its multiple roles as shareholder and industrial and social policymaker, or reconciled this with the state's decisions to allocate economic regulatory functions to an independent regulator."[19]

Steyn (2003) noted that:

> Currently the approach used by the NER to assess Eskom's price increase application is focussed on the impact of Eskom's historic cost rate-of-return on nominal price levels relative to inflation. Due to human resource constraints the NER is not able to produce these indicators independently. To date the NER has also not conducted an independent review of Eskom's cost items or of the asset valuations used to determine these indicators. … It is important to realise the NER does not just approve average price levels (which are essential for cost recovery), but also approves tariff structures for the respective customer groups. This is a critical aspect of electricity pricing because it determines the balance between the cost reflectivity of prices, the affordability of prices to the poor and rural consumers, and the transfers from higher consuming households, commerce and industry to subsidise these. While cross-subsidies are important for equity reasons they have to be weighed up against the extra costs imposed on the system as a result of the inefficiencies resulting from incorrect price signals.[20]

Following these reports, the electricity regulator set out in several documents the principles that it proposed to apply in setting the regulatory framework for retail tariffs. The *National Retail Tariff Guidelines* of August 2004 stated:

- Tariffs should enhance economic efficiency in the allocation of the country's resources.
- An important step in satisfying the above criterion is that the structure and level of tariffs should be cost-reflective. However, under special circumstances deviations in structure and level may be necessary so as to provide for other considerations.
- Where there are inherent cross-subsidies in electricity tariffs, these should be levied transparently. Licensees are required to make the effort to establish and publicise the average level of cross-subsidy between customer categories so that customers are made aware of it.

Subsequently, *Rolling out the Wholesale Electricity Pricing System– Phase 2*, published in September 2005, set out the principles for setting wholesale prices for the regional electricity distributors, municipality distributors and large customers, in the expectation that the guidelines would be updated as the industry restructured. The paper envisaged that there would be no changes to the present system of cross-subsidies, but recognised that these create tariffs that are not always efficiently cost-reflective, and, in particular, acknowledged the considerable impact of geographic cross-subsidisation.

The principles of efficiency, cost-reflectivity and transparency, particularly as applied to the practice of cross-subsidies, continue to guide the electricity regulator and have informed its regularly issued multi-year price determinations. The principles require that efficient prices are identified and a clear decision is made about the desired pattern of cross-subsidies. The prices and subsidies are then brought together to produce the final retail tariffs or tariff methodologies (for example, which costs are to be passed through, which should be

[19] Storer, D & Teljeur, E (2003). Administered Prices: Executive Report. National Treasury, Pretoria.
[20] Steyn, G (2003). Administered prices: Electricity. A report for National Treasury, Pretoria South Africa.

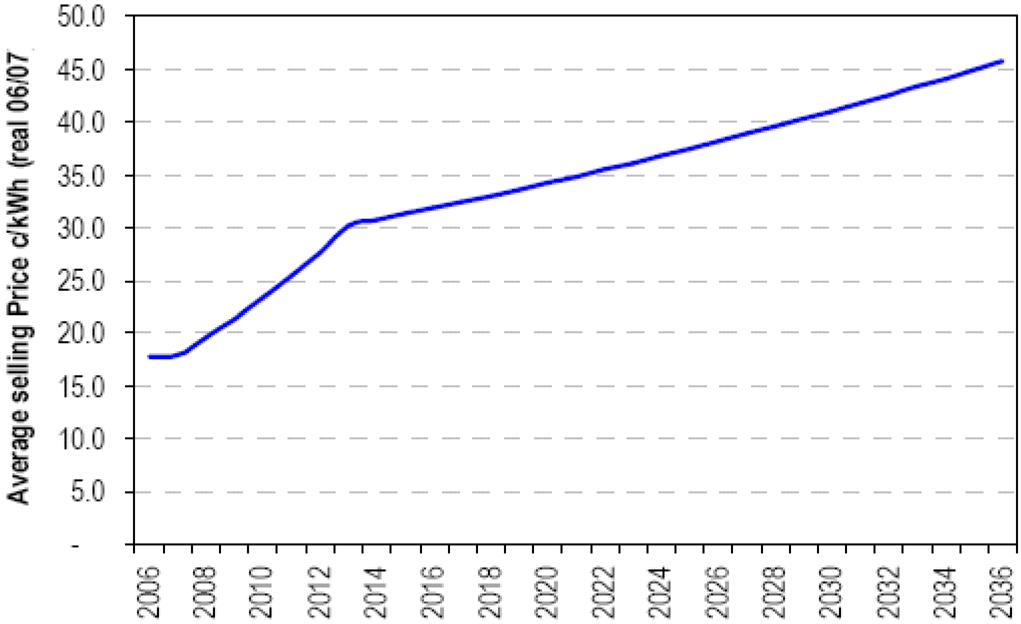
regulated, and which set competitively). Some cross-subsidies may be designed to ease the transition from the present to a more efficient tariff structure, in which case a clear timetable for achieving the goal is desirable (such as is presented by Eskom's *Forward Price Curve*). Other cross-subsidies may be intended as aspects of a more permanent redistributive or poverty-alleviation policy, and these might be funded out of the potentially considerable rents that Eskom enjoys – although the DPE as the shareholder should be required to discuss such uses with National Treasury, since redistributive expenditure is a National Treasury function. Accurate estimates of the potential rents available to Eskom are necessary for informed debate between the DPE and National Treasury. In addition, the reliability of price projections – such as Eskom's (Figure 11) – depends upon such estimates.[21]

So what should the price of electricity be? Using the coal costs from the 2007 *Forward Price* Curve, and given that the allowed revenue for generation accounts for 67 percent of total allowed revenue, the LRMC of final sales would again be 270/0.67 = R403/MWh (US$59/MWh), more than twice the 2006 level.[1] If we add the 2006 transmission and distribution costs of R67/MWh to the LRMC of R270/MWh, the final price (based on the long-run marginal costs of generation) would be R337/MWh, roughly what Eskom projected in its more aggressive price adjustment scenario for 2013, and 98 percent above the 2006 level.

If, however, a more pessimistic approach is taken to the likely capital costs of new build and provision is made for real cost escalation of 20-25 percent, then the LRMC of generation rises to about R320/MWh, plus transmission and distribution costs of R67/MWh, which gives R386/MWh – more than twice the 2007 level and not forecast to be reached until 2022 in Eskom's price projection.

[21] If Eskom's 2006 ODV is taken as R335 billion, and if it were to earn a weighted average cost of capital of 8 percent, its allowed profits (before interest but after depreciation) would be R26.8 billion. Depreciation of R9.1 billion would require a gross profit of R35.9 billion, compared with recorded gross profits of R15.3 billion. The difference is R20.6 billion on a sales revenue of R35.4 billion. Thus to recover a weighted average cost of capital (WACC) on the ODV would require a nearly 60 percent increase in the price of electricity. The average revenue per MWh sold in 2006 was R170/MWh, (R181 in 2007), so this would imply an average revenue of R269 per MWh (US$40 per MWh at 2006 exchange rates of R6.78/US$). The 2007 price would be higher, reflecting the higher coal cost in the 2007 *Forward Price Curve*. The NUS Consulting Group *International Electricity Report 2007 Cost Comparison* shows South Africa as the cheapest out of 14 countries with a cost of US$35.60/MWh, so an increase of 60 percent would put this up to US$57, still the cheapest. Looked at another way, the average 2006 revenue per MWh sold of R170/MWh includes generation, transmission and distribution, whereas the long-run marginal costs of generation used in the ODV amount to R250/MWh, at 2006 prices, (R270 with the 2007 coal costs) which is equal to the latest estimate in the *Forward Price Curve*.

Figure 11: Eskom's price projection



Source: *Eskom's Forward Price Curve 19 March 2007*

Optimal asset valuations are necessary to the establishment of appropriate price policy. Such valuations should take full account of the amounts needed to maintain and replace the assets (i.e. a proper estimate of depreciation), as well as the LRMC at present and projected fuel costs. Nor does it follow that electricity prices should be simply related to a proper asset revaluation. To a utility such as Eskom, the value of its assets is found in the revenue that it can earn, which depends on whether and how it is regulated, and what kind of power-purchase agreements (PPAs) are in place.

If Eskom had acted as a single buyer and had signed long-term PPAs with the various generation stations as they were built, these stations taken together would be worth (commercially) the net present value of the flow of revenues less all costs as defined in the PPAs. If Eskom were privatised and a sufficient number of generating companies were created to sustain a competitive wholesale market without PPAs, then the scarcity price of electricity over the next five to seven years could easily top the LRMC, since inadequate capacity is forecast and no new supplies can be brought into the system at or below the LRMC of R250/MWh. The wholesale price of electricity could therefore be anything between its present level rising towards the LRMC (with existing PPAs at existing prices gradually being replaced with new PPAs at the LRMC) and a possible price significantly higher than the LRMC.

The first point to note about the impact of accurate asset valuations upon prices is that no electricity supply industry has systematically followed best practice real regulatory accounting for long enough to provide regulatory asset value based on such accounting. In the US, with a long history of investor-owned regulated utilities, the regulatory asset value was always based on historic cost accounting. The UK started with a regulatory asset value based on the privatisation sales value, which, in turn, was based on a projection of future regulated prices starting from their (historically) undervalued level (not on LRMC or replacement cost). Most state-owned utilities similarly undervalue their assets.

Notwithstanding the inaccuracy of valuation elsewhere, it is certain that South Africa has experienced considerably higher inflation than the US, and so the extent of undervaluation based on historic cost is even greater.

The second point is that prices serve several functions – to signal scarcity, to ensure that the industry can be financed, to provide incentives for efficient investment and operation, and to redistribute income between consumers, taxpayers, banks and investors (where private). If there is scarcity at prevailing prices, then prices should be raised at the margin until, in the short run, demand falls to available supply and, in the longer run, supply rises as investment becomes profitable. Raising marginal prices appears desirable probably until 2011 for generation and some transmission. Infra-marginal pricing (i.e. pricing that has little or no effect on consumer decisions, such as fixed charges) can then address distributional issues – such as whether the owner (the DPE) wishes to collect a commercial rate of return on accurately revalued assets, or whether the owner is content for consumers to enjoy undervalued assets which have been paid for out of past tariffs and foregone state dividends (i.e. at the expense of taxpayers).

Efficient pricing requires identifying periods and locations where demand is tight or constrained (e.g. limited by transmission capacity), and then allocating the capacity costs that give rise to scarcity to the periods and customers causing the scarcity. Transmission losses are known and taken into account in planning but are not yet adequately reflected in the regional bulk supply tariffs, which only differ across the country by up to 3 percent. Transmission capacity costs should be allocated to the periods when transmission is constrained. Eskom, as a vertically integrated utility, can quite correctly trade off generation and transmission investment decisions, However, the practice sets a poor example in the event of future unbundling. (In Britain, the legacy of such decision-making for the privatised utility was that grid charges were still not correctly set after 17 years and two judicial reviews). The practice also sends misleading signals to energy-intensive users, who might choose to locate at the Cape for transport reasons, as long as they can secure electricity at the same price as that offered in Gauteng.

Many politicians oppose pricing wholesale power at the LRMC (which should also include transmission costs). Politicians are concerned that raising tariffs to the LRMC would discourage energy-intensive industries, in which South Africa appears to have a comparative advantage, and cause inflation. Both fears are misplaced. South Africa has cheap coal (even with some allowance for a carbon price) and should therefore be competitive against almost all countries with, or interconnected to, thermal electricity. It may not be competitive against countries with surplus gas that cannot be readily exported and isolated countries with cheap hydro (for example, Iceland), but there are relatively few such, and they often face other economic handicaps. South Africa has excellent sea communications, a sophisticated financial sector, potentially good infrastructure, and a stable political regime, all of which are likely to be more significant for major investors than electricity prices set at below the LRMC. Unsurprisingly, large energy users will attempt to convince the government otherwise, but their blandishments should be resisted. In practice, tariffs (more precisely the marginal energy component) would have to rise quickly to cover the LRMC and to convince financiers to lend Eskom the funds that it requires for its large investment programme.

An appropriate price regime for wholesale, as well as retail, electricity needs to be developed, charging for peak and other hours. Eskom offers a sophisticated Megaflex tariff that has an 8 : 1 ratio of winter peak (R0.61/kWh) to summer off-peak (R0.09/kWh) energy charges.

However, the generation-fuel costs alone appear to have a higher range from marginal distillate to off-peak coal than this 8 : 1, and the distillate energy cost at the peak might be as high as R1.10/kWh, to which should be added a significant capacity and transmission charge. The capital cost of peak capacity is, ideally, recovered in a relatively small number of hours per year, and the fixed costs are high (R400 000/MW/year for an open-cycle gas turbine). If the plant runs only 100 hours a year, the extra fixed costs come to R4 000/MWh, or R4/kWh, to be added to a fuel cost of R1.10/kWh, which gives a peak wholesale price of R5.10/kWh, compared to a LRMC for base-load plant of perhaps R0.25/kWh. This 20 : 1 ratio of (extreme) peak to base-load cost may make pumped storage economic, although the shortage of suitable sites for such storage and the lengthy construction period required argue against the option, other than as a long-run choice.[22]

Long-term contracts (with independent power producers, Eskom's generation division, or customers) should include a capacity charge and a time-of-day/season energy charge, with a pass-through of fuel costs based on assumed thermal efficiency. An alternative contract might be to set a strike price for the energy element in the contract for a fixed number of MWh, but allow buying and selling around the fixed level in a wholesale pool at a spot wholesale price based on short-run marginal cost plus a capacity charge. Whether such an approach is worth the extra effort compared to a system of negotiated interruptible tariffs might need study, but a limited access pool might also solve the problem of encouraging cogeneration or combined heat and power (CHP) to sell power back to Eskom at spot price.

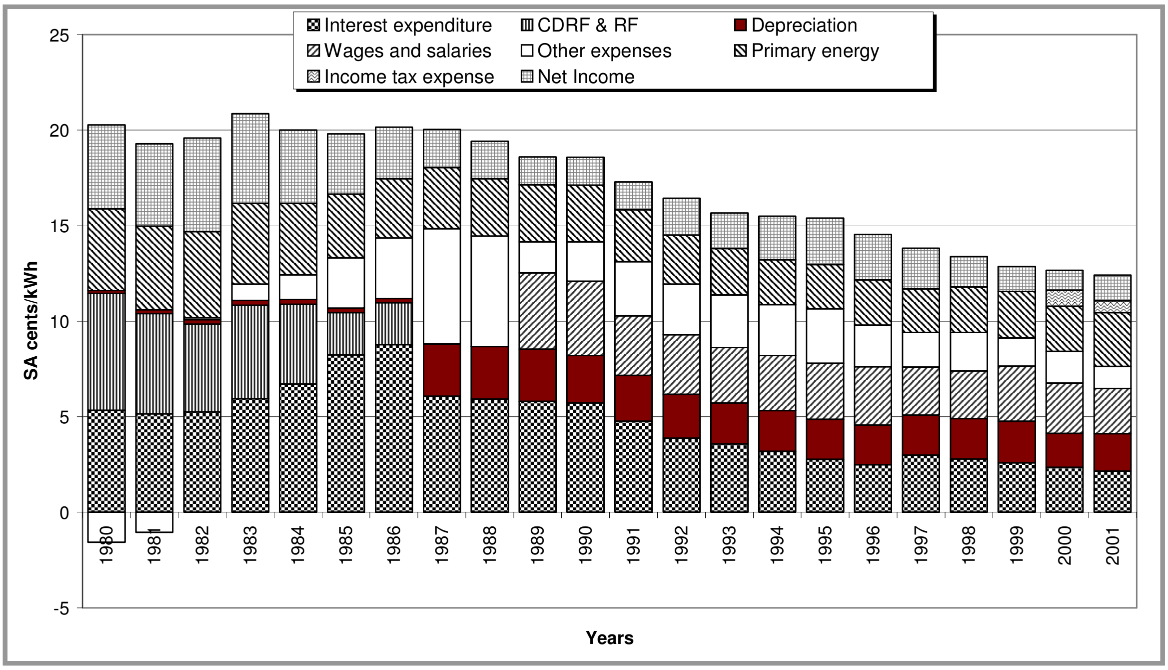
The electricity regulator sets a basket price-cap but also approves individual tariffs, partly to mute the rate at which they approach cost-reflective levels and partly to sustain continuing cross-subsidies to domestic and rural customers. Such cross-subsidies need to be calculated using careful economic and political judgement. Due consideration needs to be given to the costs of the subsidies, whether they are well targeted, and whether they undermine attempts at restraining demand in a tight-supply environment. In the interests of transparency, good governance and sound public finance, it might be preferable for the government to insist on adequate dividends from Eskom, and then to decide how these should be used (investment in rural electrification, inducements to municipalities to transfer assets to the regional electricity distributors, general poverty programmes, specific electricity subsidies). A step in this direction was taken when Eskom was corporatised in 2001, after which the capital subsidies for connecting low-income consumers were no longer funded by the utility but came from a national electrification fund.[23]

South African peak prices should be substantially raised to reflect the growing scarcity of capacity and to bring them up to the LRMC (which, at the peak, are substantially above the levelised costs shown earlier. Such a pricing strategy might be considered to increase Eskom's revenue unreasonably (depending on the approach taken towards dividend payments and the revaluation of Eskom's assets). If so, then the appropriate solution could be to lower the fixed-cost elements (transmission and distribution fixed charges) and offer lifeline rates for the first few units taken in the domestic sector (provided these are not set below the variable costs of generation, including losses).

[22] These calculations were based on 2006/7 costs. With higher 2008 oil prices, the costs of running these open cycle turbines has been even higher.
[23] Eberhard, AA & Mtepa, M: Reform and regulation of a low-price utility: the case of Eskom in South Africa. *International Journal of Regulation and Governance*, Vol 3 No 2, 77-102, 2003.

Eskom has been a potential cash cow for the past 20 years in that it has had low investment demands and has paid little in dividends. Arguably, the electrification programme was, in effect, a dividend paid to the state but reinvested in electrification. It is interesting to consider how Eskom's prices would have evolved over time since the 1980s, if it had been subject to real price controls with a rolling real (indexed) regulatory asset value. In the period of high investment, a regulator might have disallowed much of the capex as not "used and useful", to use the US regulatory term. Electricity prices would have been based on the LRMC of efficiently built plant (i.e. about half as much plant as was actually built) at an assumed efficient capacity factor. As demand grew, so Eskom would have been allowed to include an increasing share of the capacity cost in the regulatory asset value, in line with demand growth, enabling real prices to hold constant while dividends grew. As the reserve margin declined, so the ODV (and the regulatory asset value) would have increased even without investment. If the company had been allowed to earn its WACC on the ODV (which would almost certainly have been above Eskom's allowed real rate of return) then prices would by now have risen to a considerably higher level.

Figure 12: Build-up of Eskom's price in constant 2000 CPI rand cents per kWh



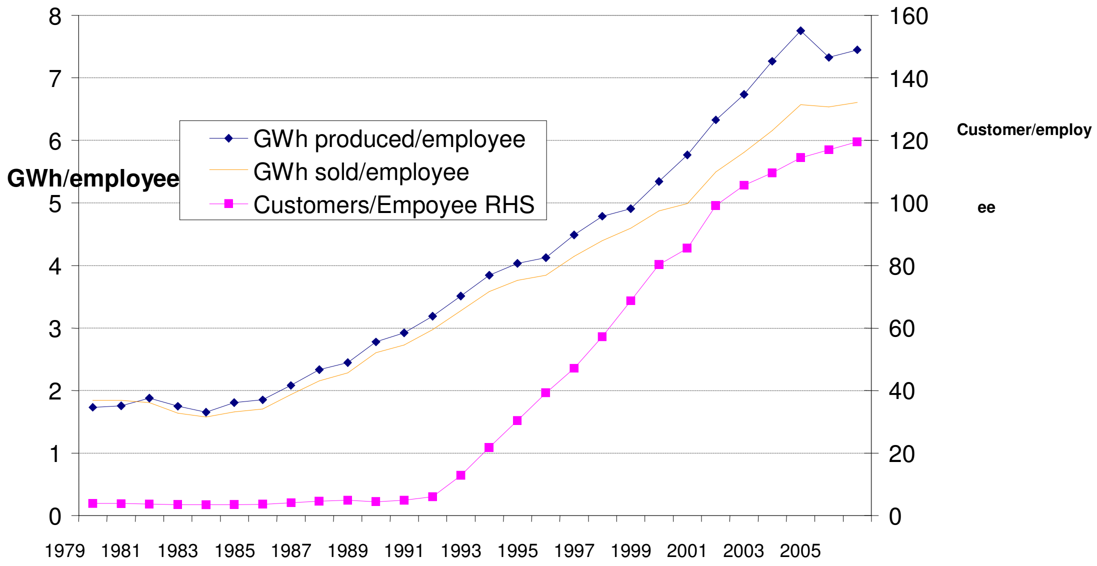
Source: Eberhard & Mtepa (2003)

Figure 12 shows that by 2001 prices were roughly one-third below their 1980 level. If prices were now raised by 50 percent they would be no higher than in 1980 – so, arguably, the combination of charging for all the installed capacity but at a sub-economic WACC produced something close to the efficient average price in 1980. Of course, the efficient tariff structure would have evolved since then. A mix of lower peak prices (caused by the large reserve margins) and higher fixed charges in the 1980s, would have gradually changed to a mix of lower fixed charges and higher peak prices. As prices rise to long-run marginal cost, so the investment should be financeable out of retained cash flow and borrowing.

Operating efficiency

Eskom's labour productivity has been growing steadily for the past decade or longer, with a slight decline in recent years as more staff has been recruited to manage planned expansion of capacity. Output and sales per employee, shown in Figure 13, have been growing at 5 percent a year, while customer numbers have been growing at 10 percent a year, as electrification has taken off and urban and rural penetration has increased.

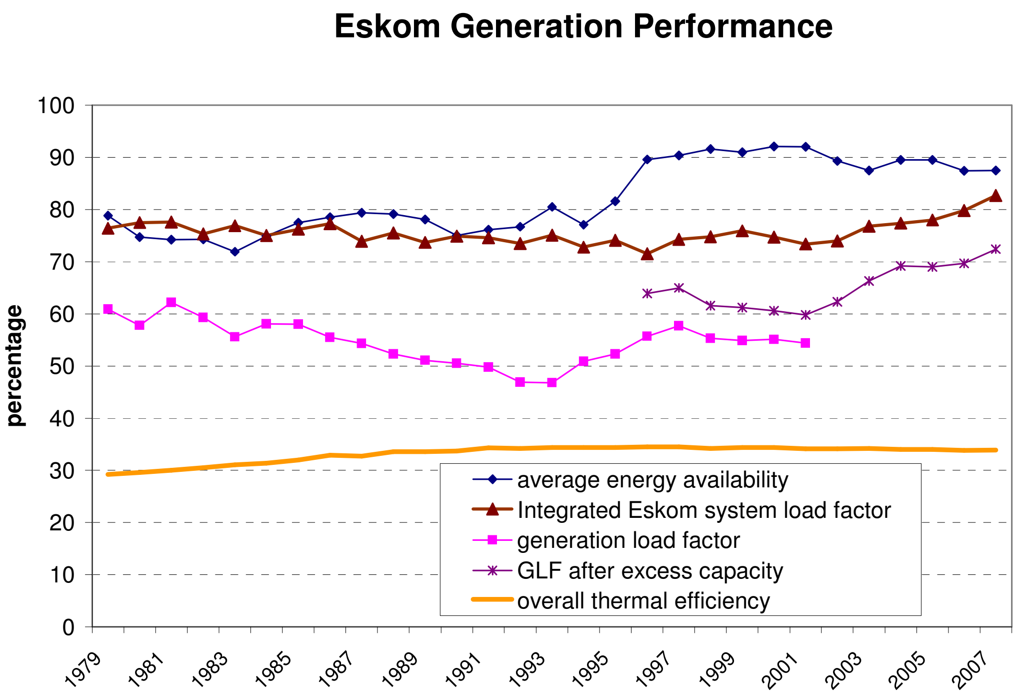
Figure 13: Eskom's output, sales and customers per employee, 1979-2006



Eskom has not had to invest much in new generation or transmission capacity for many years, and instead has been learning how to operate its existing system better. Eskom has performed well in managing its transition to a democratic economy and ensuring race and gender balance throughout its operations. Of course, an electricity company should have performed well, if it has been allowed to operate commercially in terms of recruitment and training (as Eskom has, while recognising its duty of social inclusion) and provided it has been adequately resourced (and Eskom has enjoyed strong cash flow and few demands on its profits from either shareholders, lenders or for investment demands). Eskom's generation plant is for the most part relatively modern and it operates in a benign climate (except for the constraint on water supplies). Operating under such favourable conditions, the real test (for Eskom, regulator and government) is whether the utility will be able to deliver timely investment at an efficient cost.

Figure 14 shows generation performance, with a slight decline in availability and in thermal efficiency in recent years, presumably as the system becomes more over-stretched and the less efficient plant is required to run more of the time.

Figure 14:



Source: Eskom *Annual Reports*

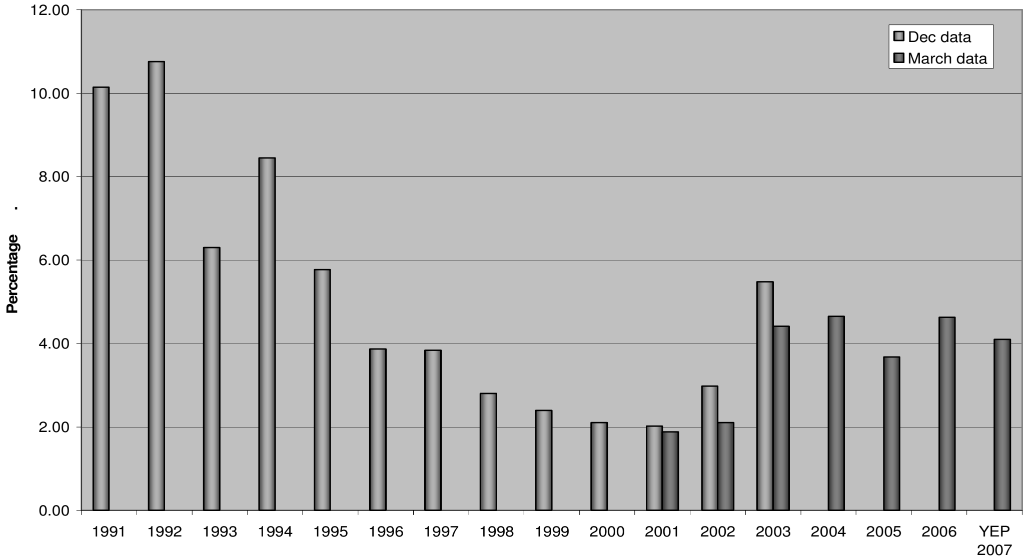
Quality and security of supply

Eskom quality of supply data

The reliability of Eskom's generation plant is conventionally measured by the unit capability factor (UCF),[24] which is the percentage of the maximum energy generation that a plant is capable of supplying to the electricity grid, limited only by factors within the control of plant management. A high UCF indicates effective plans and practices to minimise unplanned energy losses and to optimise planned outages. The unplanned capability loss factor (UCLF) is the percentage of maximum generation that a plant was not able to supply to the grid because of unplanned energy losses (such as unplanned shutdowns, outage extensions or load reductions). In recent years, Eskom has targeted a five-year average UCF of 90 percent, with a UCLF of 3 percent and planned maintenance outages equivalent to 7 percent. Figure 15 indicates recent annual trends in Eskom UCLFs, which improved in the 1990s to world-class levels of less than 2 percent but have since deteriorated.

[24] Eskom follows the predominantly European energy-based system as opposed to the time-based system used in the USA.

Figure 15: Eskom unplanned capability loss



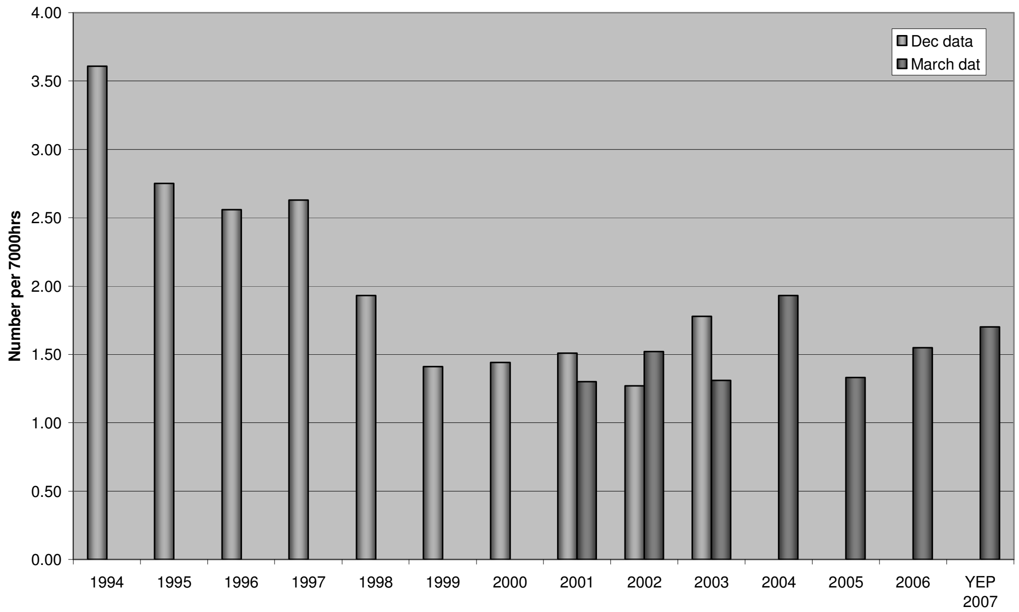
Source: Eskom

Prior to 1990, UCFs were as poor as 75 percent (international norms hover in the high 80s).[25] However, Eskom was able to consistently improve performance in the 1990s and UCFs exceeded 90 percent from 1997, reaching a peak of 92.8 percent in 2000. Since then UCFs have declined somewhat: 88.7 percent, 90 percent, 89.9 percent and 88.7 percent in the years 2003 to 2006 respectively. The drop has been caused by poor performance, mainly at the Koeberg, Arnot, Kriel and Tutuka power stations. While Eskom UCFs remain relatively good by international standards, it is clear that they are deteriorating as plant ages and load factors increase. Eskom's recent position plan (ISEP10) assumes an energy-availability factor of 86 percent. Lower plant availability can have a profound impact on supply security: when reserve margins are eroded, further unplanned outages can result in load shedding. This has become an increasing phenomenon.

Another performance indicator that has been used is unplanned automatic grid separations (UAGS), which are a measure of the reliability of service provided to the electrical grid by base-load plant over a specified period. UAGS measure the number of supply interruptions per 7 000 hours. Significant improvements were achieved in the 1990s and performance has been relatively steady since then, as shown in Figure 16.

[25] Care should be taken when benchmarking overall portfolio UCFs and UCLFs. A more meaningful benchmark would compare individual plants with similar international units.

Figure 16: Eskom unplanned automatic grid separations



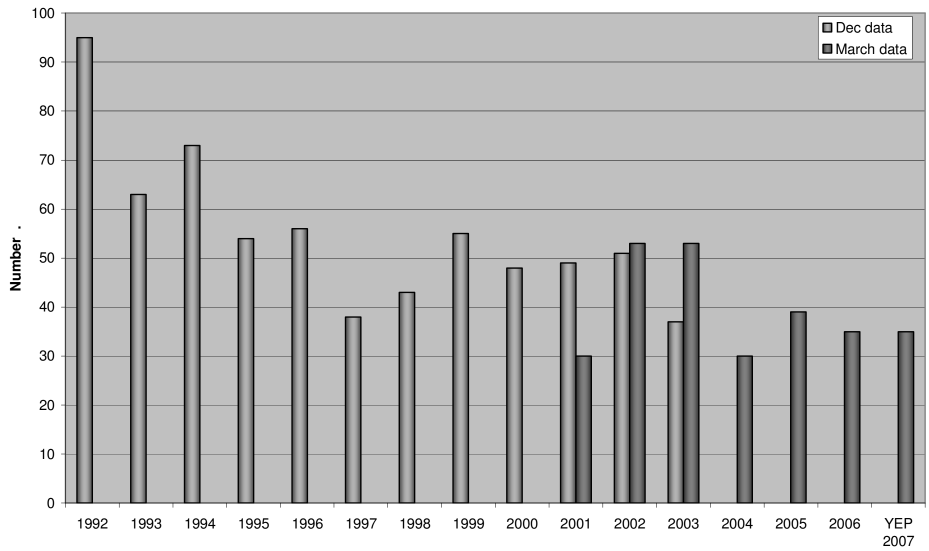
Source: Eskom

Performance indicators for generation are relatively well-established internationally. However, less consensus has been reached on how to measure and benchmark transmission performance. A working group from CIGRE (International Council on Large Electric Systems) is at present addressing the application of transmission performance indices to benchmarking – the results of this work are expected at the end of 2008. Eskom uses the following indices to report interruption performance in transmission:

- Number of interruption events (NOI) – this is the number of interruption events related to the transmission wires network that affect customers (excluding generation-capacity related load shedding)
- System minutes (<1) – this is the sum of all individual events with a system-minute value smaller than one system-minute. The aim of this measure is to report trends in the underlying performance of the system (excluding major events)
- Major events – this is the number of events >1, with a value greater than one system minute, calculated according to their severity.

The number of transmission interruptions shows some improvement over the years as indicated in Figure 17.

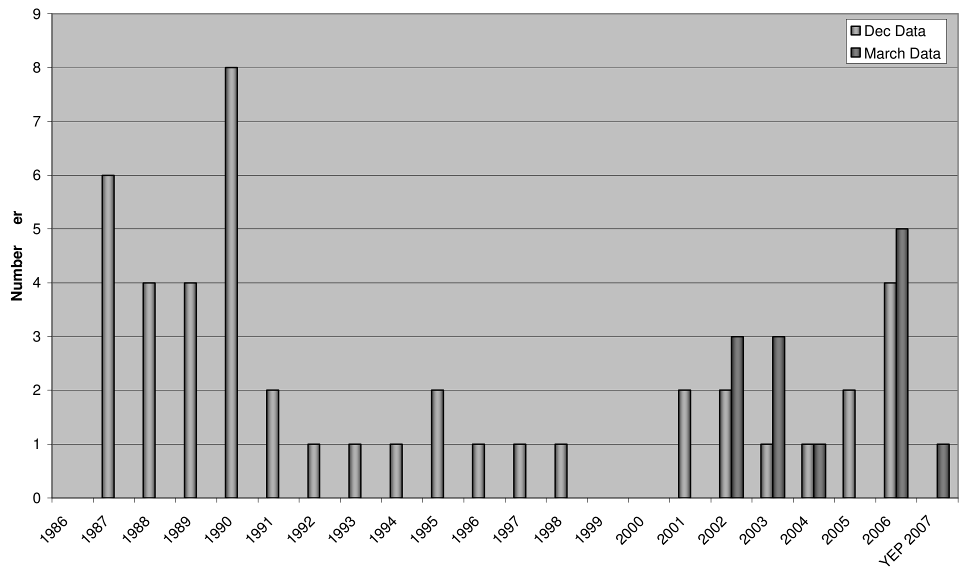
Figure 17: Eskom transmission system interruptions



Source: Eskom

The underlying performance of transmission as measured by the sum of all events with a system-minute value smaller than one does not indicate any significant trend in recent years. However, the number of major events (with a loss of greater than one system minute) is increasing and approaching levels last seen in the 1980s. This is indicated in Figure 18.

Figure 18: Eskom transmission major events



Source: Eskom

During 2005/6 there were 38 transmission-supply interruptions. However, five major incidents in the Western Cape and parts of the Northern and Eastern Cape (in November

2005 and February 2006) resulted in a total loss of 66.27 system minutes. Eskom failed, by a large margin, to meet its transmission-reliability targets.

International benchmarks for transmission-system performance, as measured by interruptions, are not readily available. However, UMS Group consultants have measured transmission-plant performance at 25 utilities, mainly in North America, Europe and Australasia. The group's findings as they benchmark Eskom's performance are summarised in Figure 19 below.

Figure 19: Eskom transmission performance benchmarked against 25 utilities

Area	**Cost**		**Performance**	
	2002 data	2004 data	2002 data	2004 data
Substation composite	Below average	Below average	Poor	Above average
Line composite	Above average	Good	Below average	Poor
Field switching operations	Good	Good	Above average	Above average
Transformers	Good	Below average	Average	Very poor
Breakers	Good	Above average	Above average	Average
Compensation equipment	Average	Below average	Poor	Poor
Instrument transformers	Good	Above average	Good	Above average
Disconnectors	Above average	Good	Below average	Good
Site and aux equipment	Below average	Poor	Average	Average
Relay	Above average	Poor	Below average	Good
Line maintenance	Good	Good	Average	Below average
Patrol and inspect	Good	Good	Average	Below average
Right of way	Below average	Excellent	Below average	Very poor

Source: Eskom

The present transmission design standard is the internationally recognised N-1 criteria, meaning that supplies would not be interrupted in the event of single line or equipment failure. Decisions to reinforce the transmission network require a business case to be made which must satisfy the following two economic criteria:

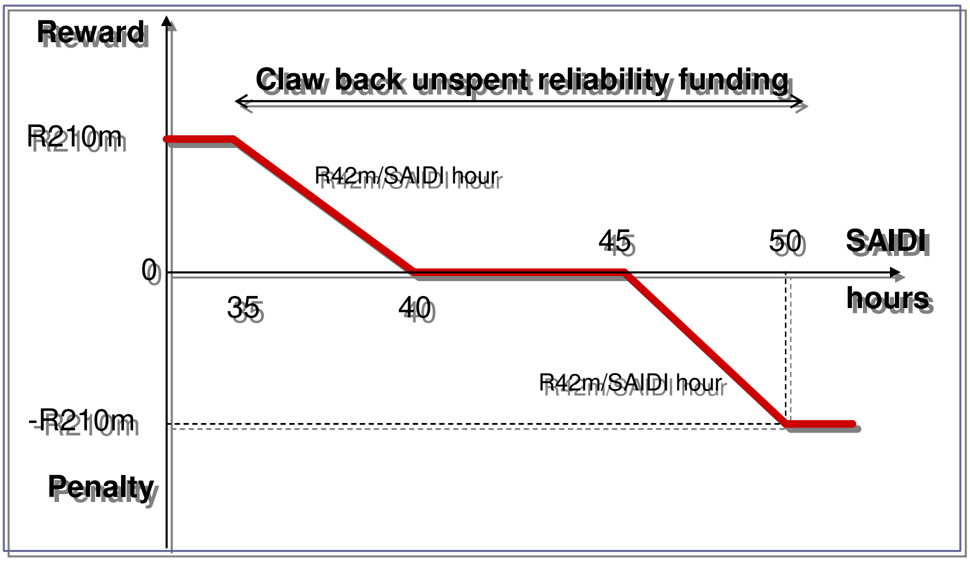
- The net present value of the reduced cost of losses and operation and maintenance is greater than the cost of the line
- The expected net present value of the cost of interruptions to customers associated with unreliability (i.e. the cost of unserved energy) must exceed the cost of the line.

There are instances where the N-1 standard is not met. Eskom undertakes regular appraisals of the reliability of the transmission system. According to a recent review by Eskom's system-operator division, 41 single-line contingencies exist that may result in loss of load, and 35 substations are unfirm and might cause load to be shed while contingency plans are being implemented.[26]

Transmission system operation is governed by the South African Grid Code, issued by NERSA. The regulator has also published a compliance management framework. In additional to national standards NRS047 and NRS048, NERSA has also published a directive on power quality, and a specification for the annual reporting of power quality performance. Eskom provides NERSA with an annual report on transmission power quality.

NERSA has also set revenue incentives in its multi-year price determination for Eskom, in terms of quality-of-supply performance targets (see Figure 20). For transmission these are relatively modest. They are more substantial for distribution. This is an important area for the future: constructing meaningful regulatory incentives (and penalties) for security and quality of supply.

Figure 20: Performance incentives set by NERSA for Eskom 2006-2008



Source: Eskom

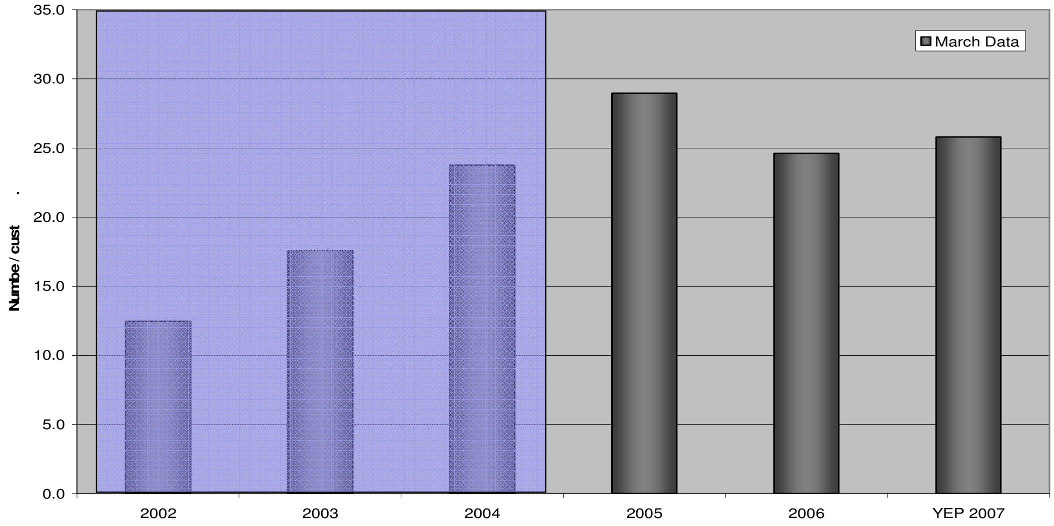
The key performance measures for distribution are:

- System average interruption frequency index (SAIFI) – defined as the number of sustained end-customer load interruptions divided by the total number of end customers
- System average interruption duration index (SAIDI) – defined as the total duration of sustained end-customer interruptions divided by the total number of end-customers
- Customer average interruption duration index (CAIDI) – defined as the average time needed to restore service to the average customer per sustained interruption – i.e. SAIDI divided by SAIFI.

[26] Eskom System Operator: Network Operations Appraisal 2005. The studies undertaken on the transmission system by the system-operator division are based on a "deterministic" (worst-case at any time) approach. In other words, if any breach of the N-1 standard, no matter how short, takes place according to the actual load patterns the substation is regarded as "unfirm". Effectively a substation is unfirm (from this perspective) if Eskom loses one transformer and load cannot be supplied by either the remaining transformers or the interconnected network already in service. This view on operational risk is significantly different from the investment criteria that created the network being assessed.

SAIFI and SAIDI data for the past six years are shown in Figures 21 and 22.

Figure 21: Eskom distribution SAIFI



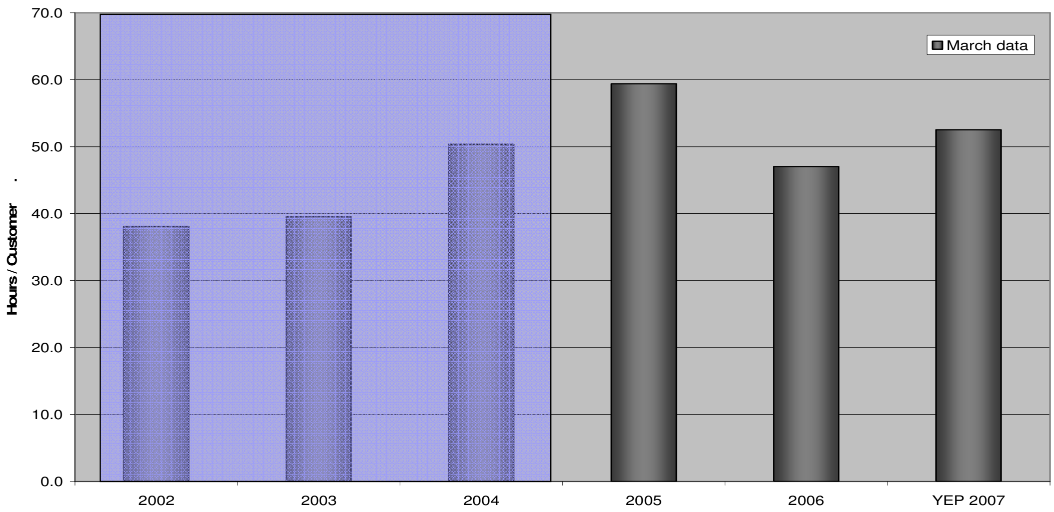
Source: Eskom (shaded area represents inaccurate data)

Care should be taken in interpreting these data. SAIFI and SAIDI appear to show negative trends. However, this trend has almost certainly been influenced in recent years by: improved data quality and scope with respect to the served customer base; linked line feeders; and automatic interruption data acquisition improvements. It should also be noted that Eskom distribution data includes the impact of transmission events and planned and unplanned distribution events. The electrification programme has a significant impact on interruption performance, as more customers are connected to rural (and often worse-performing) networks. Eskom’s investment criteria at medium-voltage level have been driven by least-cost capital investment. This has resulted in network structures with very long radial medium-voltage feeders, which often possess little alternative-supply (back-feeding) capacity. This means that both faults and maintenance-related events are likely to result in many customer interruptions.

Eskom’s performance in terms of SAIFI and SAIDI indicators generally looks much worse than that of many European or North American utilities. For example, European SAIFI figures are typically in the range 1-3 compared to Eskom’s 25 interruptions per customer. European SAIDI figures are 0.5-5 hours compared to Eskom’s 50 hours per customer. However, account should be taken of the fact that Eskom’s distribution indices are heavily denominated by rural overhead-line networks, which commonly perform worse than urban underground-cable networks.

In summary, the generation, transmission and distribution performance improvements that Eskom achieved in the 1990s in terms of quality of supply have slowed and in some cases reversed. Quality of supply will remain a major concern as the capacity of the power-system is stretched to its limit.

Figure 22: Eskom SAIDI performance

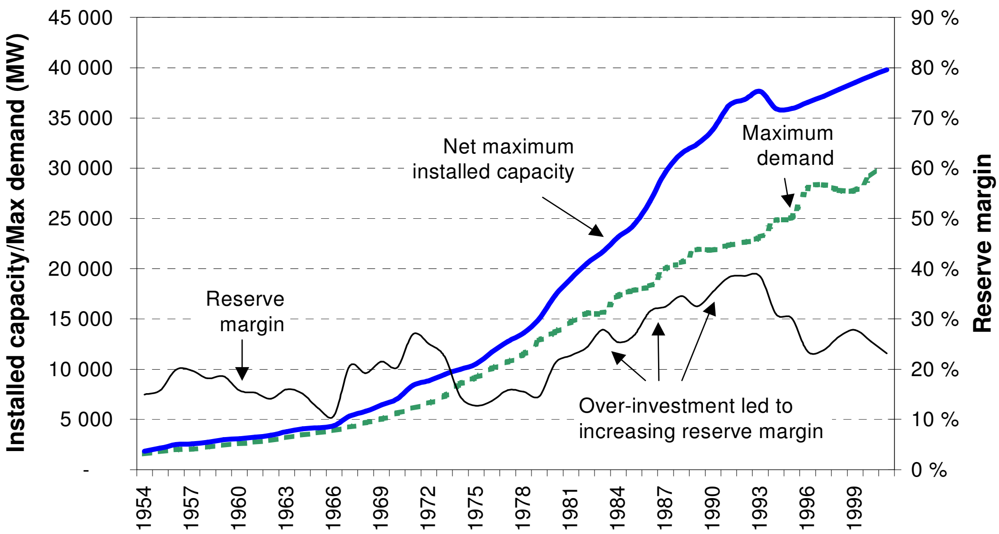


Source: Eskom (shaded area represents inaccurate data)

Security of supply

As Figure 23 indicates, reserve margins in the 20 years after 1980 were well in excess of 20 percent. Supply interruptions were rare. However, reserve margins have now been eroded and for the first time in nearly 30 years South Africa has begun to experience serious blackouts.

Figure 23: Growth in maximum demand and capacity at Eskom



Source: Eskom *Annual Reports: 1980-2002*, Eskom *Statistical Yearbooks 1985-1996*

Surplus generating capacity was created by over-investment in the 1970s and 1980s. No new generating plant was ordered by Eskom between 1983 and 2005 and no new capacity was added between 2001 and 2005.[27] Demand is now fast approaching total available generating capacity.

The Eskom reserve margin[28] over peak demand in 2006 was just 2.7 percent.[29] Taking into account additional capacity in the form of import from Cahora Bassa of 1 290MW, the reserve margin expands to about 6 percent. Eskom has long-term contracts with mineral beneficiation industries (mainly aluminium producers) which allow limited duration power interrupts totalling about 2 145MW.[30] Dynamic market participation, whereby industrial consumers bid to be switched off, is growing and could reduce peak demand by at least a 1 000MW.[31]

The system operator retains 1 900MW as operating reserves (to provide auxiliary services and maintain system stability) and, until recently, sought to hold a further 1 500MW in reserve for unplanned outages. That figure has now been increased to 2 500MW. Provision also has to be made for when plant is closed for maintenance.

If generating plant outages are significantly higher than planned, then there are serious risks of supply not being able to meet demand. It is clear that the supply/demand situation is extremely tight. In 2006, there were 213 days or 1 043 hours when the operating reserve was less than 1 900MW. There were 145 dispatch incidents where dynamic-market-participation resources were used and 33 interruptible load-sheds.[32]

Serious blackouts first occurred in the Western Cape at the end of 2005 and early 2006 following generation failures at the Koeberg nuclear plant near Cape Town, as well as a number of transmission failures. Then in January 2007, Eskom was forced to undertake rolling load-sheds around the country after an unprecedented number of generation units failed. Load-shedding resumed in October, November and December 2007 and in January 2008, Eskom was forced to cut supplies to the mines and other large customers to avoid a system collapse. Once again a large number of generation units were down due to boiler tube and other failures. At the same time insufficient coal supplies forced further power reduction. Load-shedding continued through the autumn and Eskom has forced large customers to reduce their demand by 5 to 10 per cent to avoid further cutt-offs.

The power shortages raise important questions about Eskom's planning processes.

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[27] The last three units of the last base-load power station, Majuba, were delayed until 1995 and the last unit was only commissioned in 2001. The first unit from the previously mothballed plant, Camden, was re-commissioned in 2005, and further units came on line in 2006. A new open-cycle gas plant is being commissioned in 2007.

[28] Maximum available Eskom capacity minus maximum demand divided by maximum demand on the Eskom system, times one hundred.

[29] Maximum demand in 2006 on the Eskom system (without demand-side market participation and use of interruptible contracts) was 35 441MW (25 May 2006). Total net maximum Eskom capacity was 36 398MW. Non-Eskom capacity and non-Eskom system demand is excluded from this calculation.

[30] The interruptible contracts are mainly with BHP's Bayside, Hillside and Mozal aluminium plants and with the Skorpion mine in southern Namibia.

[31] The system operator has approximately 3 000MW in emergency reserves: 2 145MW in interrupt contracts and about 1 000MW available from gas turbines, emergency dynamic market participation and emergency level one (EL1). The Acacia gas turbines in the Cape are not available for meeting peak demand as they are dedicated to providing a back-up power supply for the Koeberg nuclear power station. EL1 operation of power stations can squeeze a maximum of 450MW additional capacity.

[32] Data from Eskom System Operator.

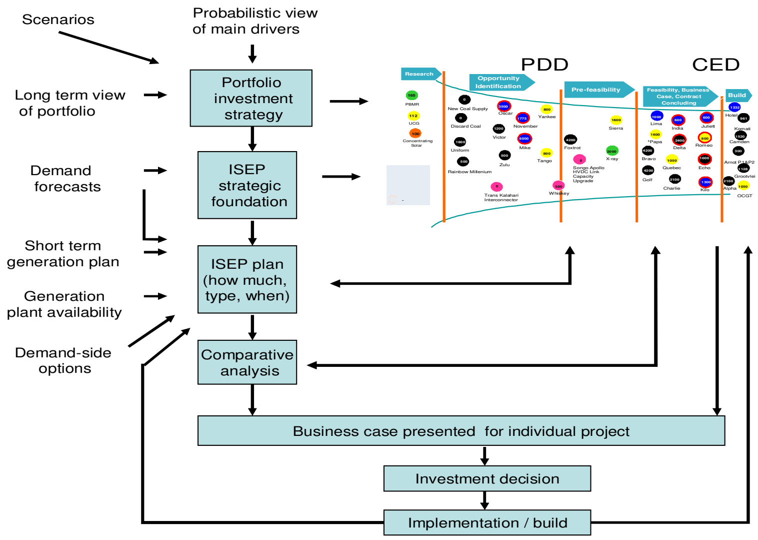
Planning and investment

Eskom's electricity planning is informed by its own Integrated Strategic Electricity Plans (ISEP). In addition, the DME produces its Integrated Energy Plan and NERSA produces the National Integrated Resource Plan (NIRP). While ISEP has been institutionalised within Eskom, NIRP is currently being undertaken by American consultants. NIRP3 is some 18 months behind schedule and there is a real risk that government and regulator planning and licence-approval processes are relying on outdated plans. Eskom's ISEP is by far the best resourced in terms of money and people. It has also been updated more regularly and better reflects latest cost and risk data.

Little capacity exists within either the DME or the National Electricity Regulator to undertake the complex modelling that underpins comprehensive electricity planning processes. However, it should also be noted that NIRP3 incorporates a number of desirable features: for example, government targets for renewable energy and energy efficiency, and carbon-tax scenarios. It uses commercially supported software (as opposed to Eskom's outdated software) and includes probabilistic sensitivity analyses that reflect short-term variations of supply and demand and simulate realistic operating conditions. It has an advanced production-cost model. Future Eskom ISEPs could benefit from incorporation of the features.

In contrast to the Integrated Energy Plan and NIRP, Eskom's ISEP planning process is closely integrated with broader business and investment planning processes within the utility. The process thus benefits from constantly updated data and information feedback loops – as indicated in Figure 26. The primary inputs into ISEP are demand forecasts (including the shape of the demand curve), plant availability, the costs of various supply options and the cost of unserved energy. The ISEP modelling and optimisation processes then indicate the loss of load expectation, the loss of load probability and the reserve margin.

Figure 26: Eskom's planning and investment processes



Source: Eskom

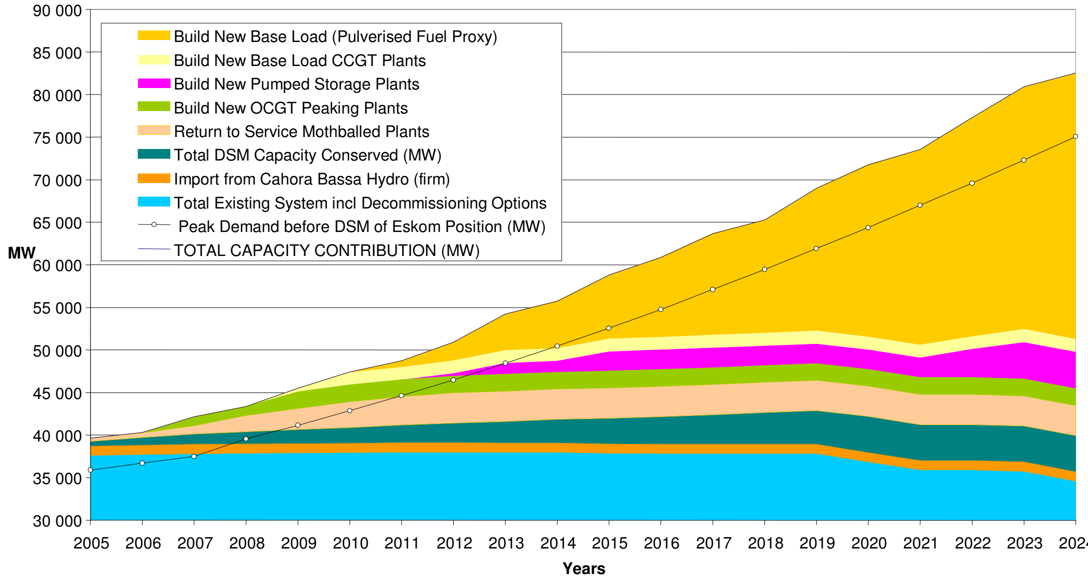
ISEP indicates the timing and mix of new generation plant over the next 20 to 25 years. Generally ISEP produces a so-called “robust plan” based on a risk analysis associated with a range of uncertainty surrounding the primary planning assumptions. It is the “least regret” plan, allowing an alternative path to be taken in the event that underlying planning assumptions change.

ISEP is informed by a portfolio investment strategy that provides guidance on the best mix of plant for different risk/reward tolerance levels in Eskom. The planning process is that, first, strategic objectives, planning assumptions, risks, uncertainties and the optimisation approach are defined. Then, demand forecasts and data on the availability of existing generation plant are considered. Next, the plan suggests how much plant, of what type, should be built and when. A comparative analysis is undertaken between projects. A range of factors are taken into account: transmission impact, possible clean-benefits, risk-adjusted analysis findings, portfolio diversification benefits, business imperatives, safety health and environment issues, and macro and socio-economic benefits. Parallel to this planning process, Eskom’s project-development department takes individual projects from concept and opportunity identification stages, through pre-feasibility studies, to full feasibility and business-case development. Such project development can involve detailed design work and interaction with potential suppliers, enabling refinements to be made to technology options and costings, which can be fed back into the ISEP planning process. In the end, the two streams come together at the investment decision-making stage, when proposals are taken to Eskom’s investment committee and its board.

In practice, these processes for planning and investment decision-making have not always been followed. When Eskom possessed excess generation capacity, ISEP had little status within the organisation. In more recent years, ISEP has been challenged by an accelerated investment plan that has emerged from Eskom’s generation division. The recent concerns around tight reserve margins and blackouts have also seen a top-down imposition of a more aggressive investment plan.

Investment plans in new generation capacity have accelerated significantly over the past two years. Eskom’s position plan (ISEP10 phase 2 in 2006) incorporated a number of new assumptions, among them the need to align the utility’s forecasts with the government’s Accelerated and Shared Growth Initiative, which aspires to 6 percent GDP growth by 2010. Eskom has estimated that this would translate to electricity demand growth of 4.2 percent. The new plan also assumed that plant availability would drop to 86 percent, and that interruptible contracts should not be incorporated into the plan’s requirements. Cost data was revised. The utility’s view of projected demand and the mix of generation plant likely to meet it is shown in Figure 27. The details of its new plan are shown in Figure 28.

Figure 27: ISEP capacity outlook



Source: Eskom

Figure 28: ISEP position plan

	Mothballed			Coal-Fired				Base Load Proxy	Gas				Pumped Storage					DSM (Load Management)				
YR	Cam (PF)	Gr'Vlei (PF)	Kom (PF)	PF (1) (3X705 MW Units)	PF (2) (3X705 MW Units)	PF (3) (6X636 MW Units)	PF (4) (6X636 MW Units)	(NX691 MW Units)	OCGT Atlantis (Peaking)	OCGT Mossel Bay (Peaking)	OCGT IPP (Peaking)	CCGT "Coega" (6X384 MW Units) (Mid-merit)	PS (A)	PS (B)	PS (C)	PS (D)	PS (E)	CLM, IMLM, RLM	Reserve margin on scenario assumptions	Unserved Energy (GWh)	LOLH (Hours)	Total SO capacity (MW)
2005	380																	102	10%	534	551	39127
2006	190																	102	9%	1017	771	39422
2007	380								616	452								102	10%	283	366	40963
2008	570	376							770	301								102	10%	167	266	43040
2009		376	202								904	384						102	11%	104	163	44957
2010		376	202									1152						102	11%	88	145	46699
2011			303	705								768						102	11%	53	104	48545
2012			202	705	705	636							333					102	12%	10	34	51126
2013				705	1410	636							999					102	15%			54842
2014						1272												102	13%		22	56114
2015						1272								1002				102	13%			58288
2016							1272	1382										102	14%		10	60892
2017							1272	1382										102	14%		34	63546
2018							1272	1382										102	14%		25	66200
2019								2764										102	14%			68964
2020								2764										102	13%			70778
2021								2764							1002				13%			73594
2022								2764											12%			76358
2023								2764								1002			13%			79944
2024								2764									1002		12%			82567
TOTAL	1520	1128	909	2115	2115	2544	3816	20730	1386	754	904	2304	1332	1002	1002	1002	1002	1632				

Source: Eskom

Eskom has decided to:

- Recommission the Camden, Grootvlei and Komati mothballed plants, which could produce 3 557MW, with the first unit coming online in 2005 and the last in 2010.

- Upgrade the six units at the existing coal-fired station at Arnot, adding 380MW
- Invest in four pumped storage units for a total of 1 332MW at Braamhoek, to be brought into service by 2013.
- Invest in open-cycle gas turbines at Ankerlig, Atlantis (588MW) and Gourikwa, Mossel Bay (438MW), commissioned during 2007.
- Invest in the Gas 1 project, which doubles peaking capacity by adding 735MW at Atlantis and 292MW at Mossel Bay, to be commissioned by 2009.
- Invest in a new base-load coal-fired power station (Medupi/Project Alpha) at Lephalele in Limpopo, comprising six units (rather than the three originally planned) producing a total of 4 500MW. The first unit is scheduled for operation in 2012.
- Invest in a further coal-fired plant (Project Bravo, an approximately 4 800MW plant at Kendall North).
- Invest in a 100MW wind farm.

The Eskom board will also consider investments in nuclear plants (although the first units could probably not be commissioned before 2017).

The cost of peaking power from open-cycle gas turbines and pumped storage will be very expensive. The decision to place gas or distillate peaking units near the Cape appears to make sense given its distance from the coal-fired stations that might otherwise be required to provide the electricity: the extra cost of transmission from the northeast to the southwest just for peaking capacity has probably been calculated as prohibitive.

However, when it comes to base-load power for the Cape, the decisions are more complex. It has been shown that gas, particularly LNG, is very expensive for base-load power, even though the build-time and capital costs for plants using such fuel are lower. The alternative is presumably to build another coal-fired plant in the northeast and additional transmission capacity to deliver the power to the Cape, some 1 600 km away. At US$0.5m/km, the extra cost to deliver 4 000 MW would be at least US$800m/km (ignoring the cost of the transformers and switch gear that would be needed). This gives an extra cost of US$200/kW (R1 400/kW). NIRP2 shows the capital cost of new coal-fired plant as R12 324/kW at 2003 prices, since when the consumer price index has increased by 10 percent. These calculations show that transmission costs would increase by 10 percent the effective capital cost of coal-fired plant delivering to the Cape, and increase by, perhaps, a further 7 percent operating costs (due to marginal transmission losses).

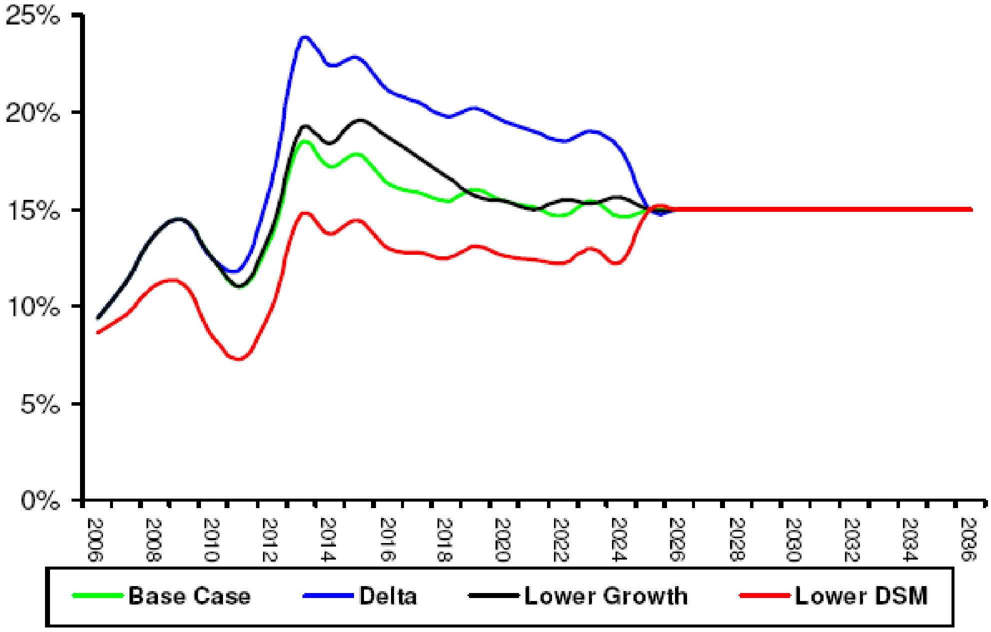
At recent fuel prices, the cost of new nuclear power may now be lower than that of power provided by LNG – although the capital cost of nuclear is considerably higher. However, it is difficult to believe that base-load nuclear power could be competitive against base-load coal plant, even given the extra cost of transmission borne by the latter. Base-load nuclear also poses security-of-supply problems – its large block-size exacerbates the power shortages created by necessary refuelling, as well as outages. Nuclear looks competitive for the Western Cape only if the capital cost and construction period have been correctly estimated, a relatively low cost of capital is assumed, and a carbon price greater than US$7 per tonne of CO_2 is accepted.

In the medium term, the focus will be increasingly upon the need for mid-merit plant and the question of whether it is more cost-effective to invest in further coal-fired plant (higher capital cost but lower fuel costs, and low initial load factors) or CCGT plant (lower capital cost but higher fuel costs, and more readily suited to immediate mid-merit operation).

Cumulatively, the planned electricity-industry investments will not create a reserve margin in excess of 15 percent. In many years the reserve margin is likely be lower. A number of risks could erode reserve margins and lead to further blackouts. These risks include higher than predicted unplanned outages, higher than predicted demand growth, coal delivery constraints, fuel supply problems to the open-cycle gas turbines, delays in environmental approvals and transmission right-of-way expropriations, equipment supply constraints, scarcity of skills, and unforeseen delays in commissioning and building new plant.

Figure 29 shows the reserve margin falling to 7 percent unless demand-supply management is rapidly promoted. Eskom recognises the desirability of restoring a 15 percent reserve margin as soon as possible. This will only be possible if Eskom's investment programme in new generation capacity is complemented by an accelerated effort the contract the private sector participation in cogeneration, IPPs and energy efficiency investments.

Figure 29: Reserve margins under different scenarios



Source: Eskom

Eskom has massively expanded its capex programme to respond to the security of supply concerns. The original R97 billion five-year capex programme has been expanded to R350 billion. However, since new base-load capacity will only be brought into commission in 2011, at the earliest, security of supply in the next five years remains under threat.

Financing the investment programme

Eskom's funding strategy is to borrow long in the domestic and international bond markets. Its €500 million bond of 2005-13 which offered a 4 percent coupon was three times oversubscribed. The utility has access to a number of international sources (European Investment Bank, Japan Bank for International Cooperation, Asian Development Bank, which offer 20-25-years terms, as well as export credit agencies, which offer 15-year terms. It can also borrow cheaply long term in the domestic market (to 2033). The investment plan projects capital expenditure rising from R27 billion in 2007/08 to nearly R40 billion in

2009/10. Financial requirements rise to a projected R30 billion by the fourth quarter of 2008/09, but the planned funds are expected to cover this. Putting this into some kind of context, the 2006 accounts show cash flow from the company's operating activities of R11.7 billion (R13.4 billion),[33], physical investments of R10.2 billion (17.3 billion), net debt issued of R10.3 billion (R8.5 billion), net interest paid of R0.2 billion (zero) and dividends of R1.6 billion (zero). Thus, in 2006, investment was 87 percent covered by debt issuance (and, in 2007, only 50 percent covered), while cash rose from R4.8 to R7 billion (and to R7.7 billion in 2007). The numbers vary considerably from year to year – in the 15 months to 2005, the net debt issued was 38 percent of the physical investment, while in the year before that (2003) the R5.9 billion investment was financed out of the cash generated from operations (R13.3 billion) with a net debt repayment of R0.7 billion.

Eskom's company balance sheet at end 2007 appears strong. Its property, plant and equipment assets at a written-down value of R76 billion understate their true value. Its total physical assets, including about R9 billion in fuel, inventories and investment in subsidiaries, amount to 81 billion, backed by 54 billion equity, and, by subtraction, net debt of R27 billion.[34] The 2007 accounts show Eskom's debt/equity[35] ratio as 0.30, although the planned capital expenditure is projected to be 67 percent debt-financed (*Annual Report 2007*, p.iv). The debt/equity ratio would of course be much lower if the assets were to be revalued, but revaluing the assets would not help finance investment unless it were accompanied by an increase in future cash flows, i.e. in the price Eskom is allowed to charge for its electricity.

Price increases will be necessary if Eskom's credit standing and access to low-cost borrowing is to be maintained. Increases would ease the burden of the utility's investment programme and have the added benefit of reflecting long-run marginal costs (and predicted scarcities) in prices.

Electrification programme[36]

Connections

South Africa has undertaken an impressive electrification programme over the past 15 years. Eskom adopted the "electricity for all" slogan in 1987, but a coherent programme only emerged in 1992, with the announcement by the utility's chief executive of national connection targets. Eskom's monthly connection rate, which in January 1991 stood at below 1 000, rose to only about 5 000 by the end of that year, but rose dramatically to 30 000 connections in December 1992. A much larger programme was endorsed by the new government in 1994 as part of its Reconstruction and Development Programme.

The progress of the programme is shown in Figure 30. The number of annual connections rose steeply from 1991 to a peak of almost 500 000, and dropped to about 250 000 annually after 2001.[37] The total number of new households connected between 1992 and 2003 was 4.6 million, of which Eskom connected 2.9 million (almost two-thirds).

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[33] Figures in brackets are the amounts from the 2007 accounts.

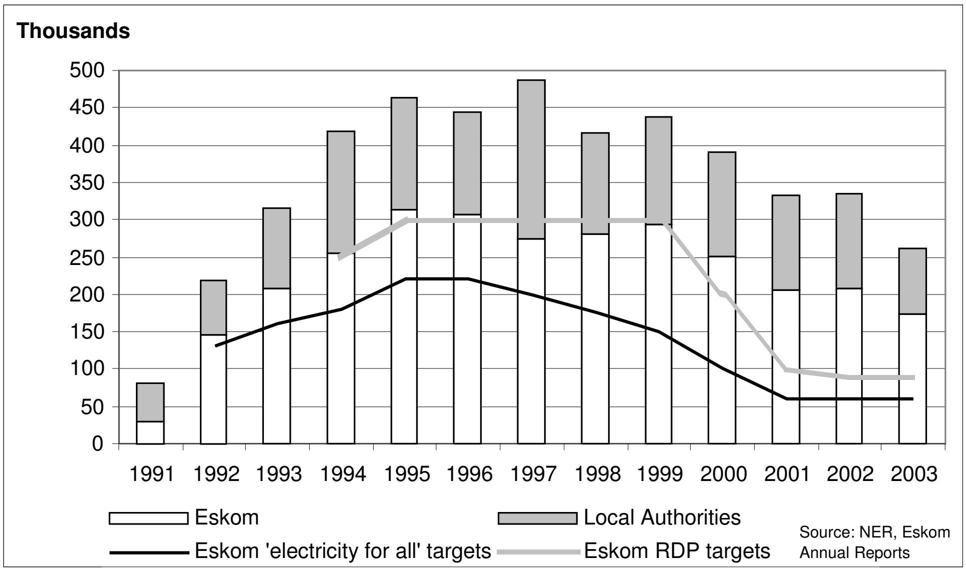
[34] This considerably simplifies the detail of the full financial balance sheet, which includes derivative positions on fuel, etc.

[35] Including long-term provisions. *Annual Report 2007*, p77.

[36] This section draws directly from a recent paper by Marquard, A & Eberhard, A (2007). South Africa's electrification programme: an overview and assessment. MIR Working Paper, Graduate School of Business, University of Cape Town.

[37] Rates since then have remained about the same, although are reported on a different basis (April to April instead of January to January).

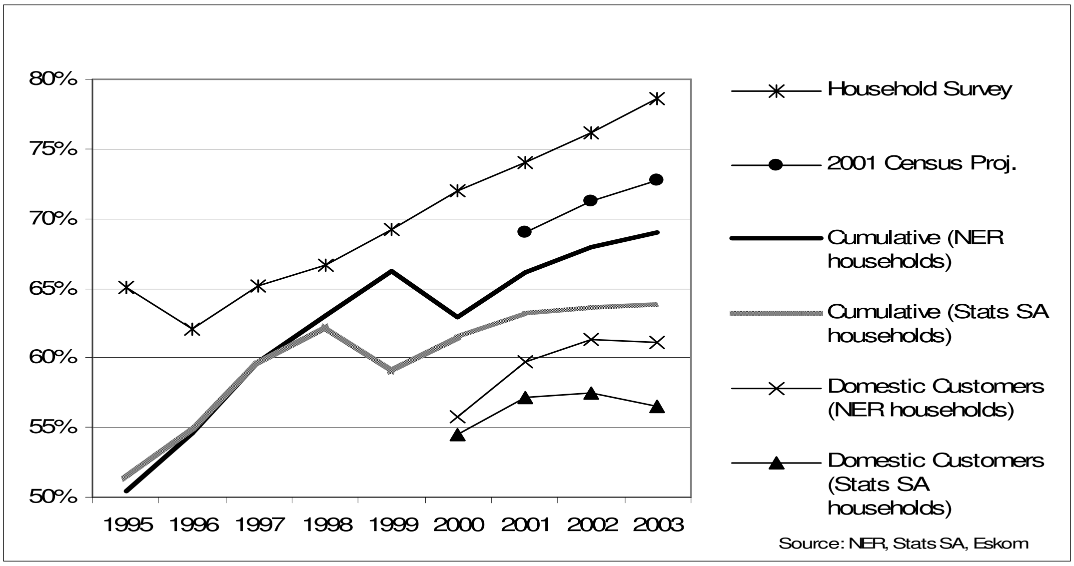
Figure 30: Annual electricity connections in South Africa



Source: Marquard and Eberhard (2007)

While the data on the number of new connections is reasonably accurate, data on the overall percentage of households that are connected is much less certain. The uncertainty of such data impacts directly on policy-making and electrification planning for universal service, as well as financial planning and subsidy allocations. The ranges of estimates of the proportion of households that have an electricity connection in South Africa are indicated in Figure 31.

Figure 31: Estimates of households with access to electricity



Source: Marquard and Eberhard (2007)

Looking at Figure 31 from the top, the first line reflects the proportion of households with electricity reported by StatsSA's October Household Survey and General Household Survey[38]

[38] Corrected, by linear extrapolation, for time of year – the October Household Survey and General Household Survey are carried out in August and October, whereas connection figures are for the end of December. In the

– this information and similar data provided by the census are derived from a survey question on how many households use grid electricity for lighting, which, given that qualitative studies unanimously report lighting as the first application of electricity, indicates accurately which households are electrified. The General Household Survey figures are about 5 percent higher than the census figures which are used by the Department of Minerals and Energy. Eskom uses, among other indicators, a projection based on the 2001 census using a constant number of people in a household (four people, which is higher than the 2001 census indicated). The totals reached by this calculation are 5 percent higher than those estimated by the National Electricity Regulator. Since some, if not all, of the energy regulator's household figures are wrong,[39] a recalculation shows a much lower proportion (the next line). Finally, NERSA numbers are based on a baseline figure for domestic customers of all utilities; actual reported figures for domestic customers indicate an even lower percentage of electrification.

It is worth noting that:

- The range of possible electrification figures is significant, and worrying (57-78 percent) and demands further research
- The "domestic customers" are probably undercounted due to non-reporting by local authorities[40]
- The household surveys have a 5 percent margin of error, but are probably over-reporting electrification rates, which is implied by comparison with the more comprehensive 2001 census
- The regulator's household figures are generally probably too low, but the household survey figures might be too high
- The survey figures reflect electricity use, which is probably boosted by illegal connections to the grid – this might explain the discrepancy between the proportion of households reported to be legally connected – as low as 55 percent in 2003 – and those found to be simply connected – as high as 70 percent in 2003).

Electrification costs and financing

Three phases can be identified in the evolution of the financing of the electrification programme. In the first phase, from the late 1980s to the mid-1990s, there was a diminishing but influential belief that electrification could be self-funding. Increasingly strong evidence presented itself that this was not the case. Nevertheless initial forays into electrification by Eskom were partly based on the assumption that consumption by electrified households would rise to an average level where operational and capital costs could be recovered, and that this rise would create a new market for Eskom's overbuilt generation sector.

Whatever the merits of the assumption, its promulgation enabled the utility to embark upon widespread electrification. With the simple aim of facilitating access to electricity, capital costs for new connections were subsidised. Prepayment metering was introduced, usually coupled with a simple tariff based only on consumption (no fixed charge). "Non-technical

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General Household Survey data, 2000 and 2001 have been linearly extrapolated due to lack of data in these years.

[39] For instance, the 2001 National Electricity Regulator household figure was 10.7 million (end of 2001), whereas the 2001 census figure was 11.2 million (October 2001)

[40] The electricity regulator claims that under-reporting is rife, but is not prepared to estimate a margin of error – back-of-the-envelope calculation based on guesswork estimates that this figure might be up to 18 percent too low.

losses" (electricity theft through illegal connections and/or bypassing the meter) became widespread.

Eskom's return on its electrification programme has depended on: cost per connection, support costs, consumption, revenue losses and tariff levels. Given tariff levels and capital costs, it was estimated that consumption levels of 350kWh per month would be required for break-even, whereas average consumption in newly-electrified households is around 100kWh/month.[41] By the mid-1990s, it became apparent that electrification was not going to be self-funding. In fact, Eskom funded its own programme, and from 1996 to 2001, the national programme, from several sources. In the early days of the programme, these included electrification bonds. Most funding, however, came in the form of a cross-subsidy from industrial users, as well as various (relatively small) hidden cross-subsidies that took the form of added organisational capacity (such as secondment of staff to the Department of Minerals and Energy). Eskom also provided funding for municipal electrification programmes via annual transfers and allocations that were managed by the National Electricity Regulator.

At the end of the 1990s, the state took an unexpected decision to fund the capital cost of the programme entirely from the fiscus. The decision coincided with the introduction of the Eskom Conversion Act, which obligated Eskom to pay taxes and dividends. At the same time (pending a final decision taken in 2002), the state decided to introduce free basic electricity, also to be funded from the fiscus, and targeted at low-income households. By 2005, the state was also funding bulk infrastructure development for electrification. The state's free basic electricity policy specified the provision of a "self-targeted" subsidy of 50kWh of free electricity per month to poor households. The qualifying households were identified either by their willingness to apply for and accept a limited supply capacity of 10 amps, or by their very low consumption level (in which case the subsidy is automatically allocated).[42]

It was estimated that the subsidy would cost around R600 million a year, increasing by R80 million a year, depending on progress with electrification, with an upfront capital cost of about R600 million (to install/replace metering equipment, etc). The policy was drafted by the Department of Minerals and Energy's electricity policy section, but responsibility for it has now been transferred to the Department of Provincial and Local Government, where it is implemented along with a basket of other free basic services. National implementation has been slow and uneven, because of lack of capacity in local authorities, and the requirement that local authorities conclude "service-level agreements" with Eskom in Eskom areas of supply within their jurisdiction.[43]

Figure 32 portrays real[44] capital expenditure in the programme, and the real cost per connection.

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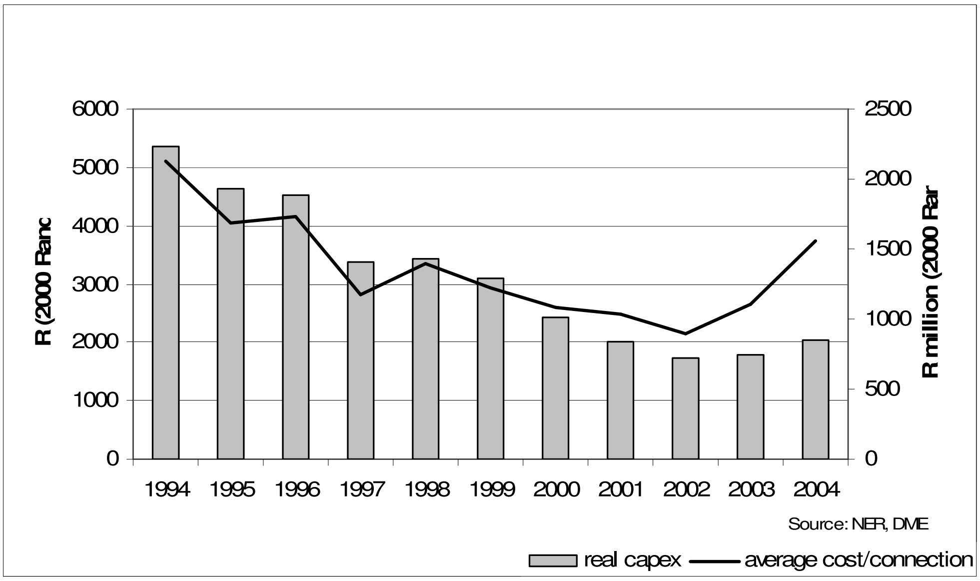
[41] Davis, M 1997, *Electrification and institutional reform in power utilities: case studies in South Africa and Switzerland,* unpublished DPhil thesis, University of Sussex

[42] South African Government Gazette 25088, 2002, Pretoria

[43] Department of Minerals and Energy. Annual Reports 2003-6, Pretoria.

[44] Nominal amounts deflated using the Producer Price Index (2000=100).

Figure 32: Average cost per connection and total electrification capex



Source: Marquard and Eberhard (2007)

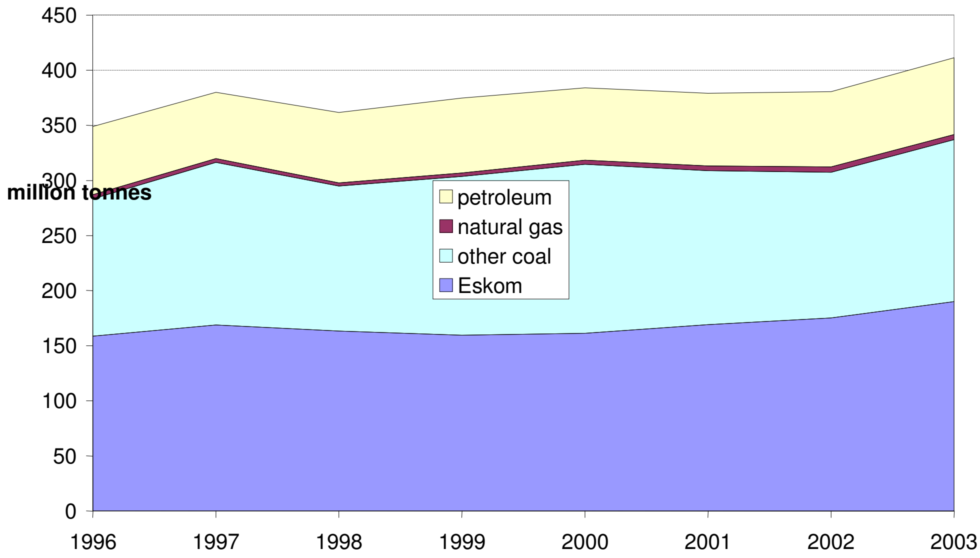
While real funding has decreased over the period, connection rates remained high (until these began to decline in 2001) due to the astonishing reduction in real cost per connection since the start of the programme. Most innovation took place in the 1990s. Then, in the early 2000s, costs began to rise again. The rise can be explained by two facts: first, the programme had by then become focused on more sparsely populated rural areas (some of which required significant additional infrastructure); and second, the prices of basic commodities required by the programme (steel, copper, aluminium) began to increase significantly. While the DME has raised its estimated average cost per connection to about R4 400 (nominal 2006) for planning purposes, Eskom officials estimate that costs will rise to about R10 000 (nominal) in the next five years.[45]

Environmental performance

The major environmental impact created by Eskom's operations derive from its generation stations. Coal-fired stations account for 92 percent of electricity produced. Nuclear contributes about 6 percent and hydro and pumped storage about 1.8 percent. Bagasse and gas (kerosene) turbines contribute negligible amounts. Coal-fired stations emit carbon dioxide (a major greenhouse gas responsible for climate warming) as well as sulphur dioxide, nitrogen dioxide, nitrous oxide and ash/dust particulates.

[45] The actual expenditure per connection is higher than this – R4 400 is around R3 100 in 2000 Rands, lower than the 2004 figure; the Eskom figure is about R5 900 in 2000 Rands, assuming producer price inflation of about 5 percent.

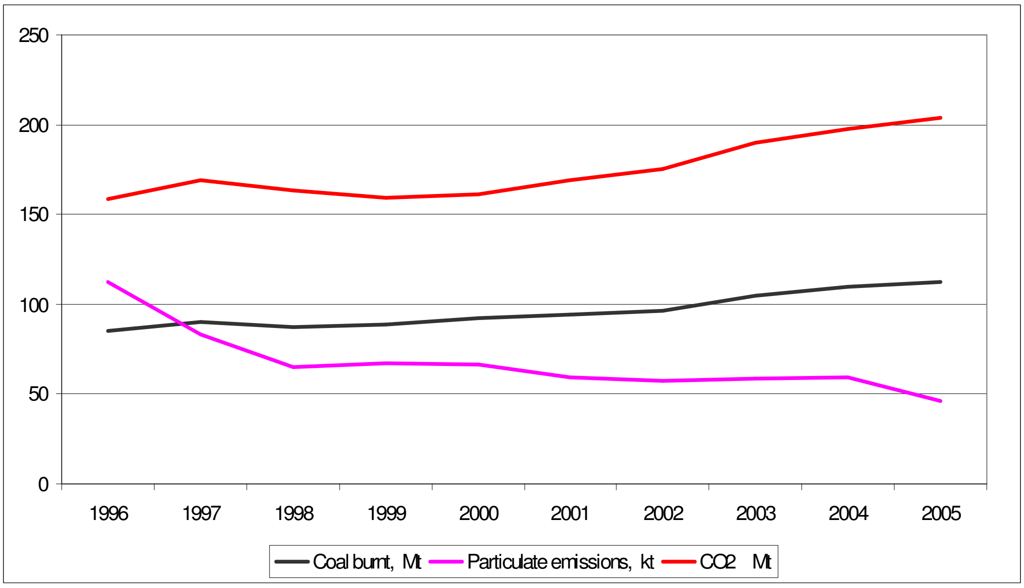
Figure 33: South Africa's CO_2 emissions



Source: Energy Information Administration of the US Department Of Energy [46] and Eskom Annual Report

Eskom contributes nearly half of South Africa's CO_2 emissions. Coal usage continues to increase as coal-fired stations experience higher load factors and higher electricity demand. Further coal-fired stations are planned. Eskom emitted 203 million tonnes of CO_2 in 2006, or about 1kg CO_2/kWh produced from coal-fired stations.

Figure 34: Eskom coal usage and emissions



Source: Eskom Annual Reports

Coal used by Eskom has a high ash content (about 29 percent). Electrostatic precipitators and bag filters reduce particulate emissions by 99.9 percent and Eskom has achieved major

[46] at http://www.eia.doe.gov/cabs/safrenv.html

reductions in recent years – from 0.63kg/MWh of electricity produced in 1996 to 0.21kg/MWh in 2006.

The average sulphur content of coal burnt by Eskom is 0.9 percent. Eskom does not employ flue-gas desulphurisation and sulphur oxide and nitrogen oxide emissions are higher than those recommended by European or World Bank standards. Eskom emitted 1.76 million tonnes of sulphur dioxide and 0.87 million tonnes of nitrogen dioxide in 2006.

South Africa is a water-scarce country and minimising water consumption is a major concern. Eskom's Kendal and Matimba power stations are dry-cooled. Eskom's water consumption has remained more or less constant at about 1.3l/ kWh of electricity sent out.

Low-level radioactive waste from Eskom's Koeberg nuclear plant is stored at Vaalputs in the Northern Cape. Spent nuclear fuel is stored on a temporary basis on the Koeberg site.

Summary

Eskom has been able to reduce prices in real terms while also bringing down its debt and undertaking a major electrification drive. However, it might not have been best policy to allow prices to fall so far below long-run marginal costs when surplus generation capacity was being eroded and a wholesale market was being planned that would allow new private-generation investments.

Quality of supply has deteriorated as ageing plant is run to the maximum. Delays in investment planning and ordering, partly caused by indecision over industry restructuring, have prejudiced security of supply. Generation outages and problems with transmission caused load-shedding, but stimulated useful learning about the potential for demand-side management. Security of supply will be tight over the next seven or more years, even with Eskom's ambitious return-to-service and new investment programmes, Delays in committing to independent power producers might further prejudice security of supply. The planning and investment-approval process remains divided among too many different bodies.

Eskom's balance sheet presents asset values at written-down historic cost and, as a result, appears to significantly undervalue all major asset classes. This in turn leads to an apparently satisfactory rate of return at existing prices. A more realistic asset valuation would show that the present rate of return is far too low, indicating that prices are too low. Prices should rise to help to finance the investment programme. Prices may need to double or possibly more to reach the LRMC. In addition, present tariffs are failing to properly reflect marginal costs by time and region – marginal prices (particularly at the peak) should be raised as a matter of urgency, to underpin any proposed demand-side management.

4. ISSUES AND CHALLENGES

Core problem areas and proximate causes

South African's electricity-supply industry faces seven principal challenges.

1) There is an urgent need for capacity expansion. Investment demands are high, costly and pressing. Security of supply has been compromised. The pressures on capacity have been caused not so much by economic growth rates as by delays in reforms and unclear lines of authority and decision-making. The reform process has stalled to the point that radical reform would now probably do more damage than good (in terms of costs and disruption), given the extreme stresses upon the electricity system and its need for substantial "new build" and refurbishment. Nevertheless, a number of adjustments and improvements need to be made to capacity-planning processes, the system for allocating new-build opportunities (to Eskom or the private sector), and procurement and contracting mechanisms.

2) Policy-makers should try to ensure that Eskom's investment programme is done at the least cost and will be undertaken efficiently. There are several issues here. One is that state-owned enterprises typically suffer from soft budget constraints (they can expect the state to step in with loans or higher prices if insolvency looms). As a result, state-owned enterprises are under less pressure to cut costs than if they were subject to the private-sector discipline of takeovers and bankruptcy. Another issue is that investment planning expertise and information is concentrated in Eskom, a directly interested participant in potential competition with independent power producers and import power-purchase agreements. The National Energy Regulator of South Africa (NERSA) and the Department of Minerals and Energy (DME) suffer from asymmetric information, a lack of expertise and unclear responsibilities. The regulator has the merit of independence and impartiality, and can contract for expertise, but is in a weak informational position relative to Eskom – a problem that is exacerbated by the urgency of investment decision-making.

3) Eskom has been unable to keep its existing plant operating at adequate levels of reliability. Recent blackouts are not only a result of inadequate generation capacity. There have also been unprecedented breakdowns and failures in generation plant. There is a need for reviewing Eskom's management, its primary energy procurement strategies and its maintenance and operation systems.

4) There is a need to implement the pricing principles of efficiency and cost-reflectivity, and the principle of transparency in any subsidy programmes. These principles have been accepted by government and the regulator, but have not been systematically put into effect. The problem is that, as a state-owned enterprise, Eskom is subject to a particular price regime. Its prices are regulated at average cost based on historic book-valued assets, a low weighted average cost of capital and, at times, a waiver on dividend payments. If prices were to be raised to efficient levels (at least to the LRMC , and sufficiently high to be acceptable to new independent power producers), then some of the pressure on capacity would ease in the short run. In the medium term the need for additional capacity would also be reduced – the amount of such a reduction would depend on the strength of the demand response to, among other factors, the new prices.

Setting efficient price levels would also have profound implications for industrial policy. Present low prices send incorrect signals to those engaged in energy-intensive investment, particularly when efficient or scarcity prices are set to considerably exceed the LRMC for the next few years. Nevertheless, until recently, new energy-intensive industries were encouraged with favourable long-term contracts offered at prices below the already under-priced tariffs and far below efficient prices. Setting prices at more efficient levels would not necessarily prejudice South Africa's comparative advantage in most energy-intensive industries.

The management of required price increases would create new challenges for governance and oversight. Efficient prices would dramatically increase cash flow. The money would reduce the scale of extra debt needed to finance expansion, but would also reduce the tightness of the budget constraints that Eskom faces, unless its owner (government), insists on large dividend payments. Managing large dividends puts strain on civil service bureaucracies, and would need careful administration.

5) Transmission constraints are becoming serious and transmission performance (measured in terms of major interruptions) has deteriorated, exacerbating power shortages in the Cape and endangering security of supply in other regions. The cause is a combination of specific maintenance problems and inappropriate investment criteria.

6) Distribution performance by municipalities is generally poor and could deteriorate further, at great economic cost. About half of South Africa's electricity distribution is delegated to municipalities, which lack appropriate, politically-insulated commercial structures for the management of distribution and supply, and which, in many cases, have failed to maintain infrastructure and retain suitably skilled staff. The establishment of regional electricity distributors (REDs) is stalled by constitutional and other legal objections. Various key decisions on national electricity-pricing policy, local government surcharges and the ownership and control of the regional electricity distributors remain to be resolved, while the actual merger of Eskom with municipal distribution management, staff, assets and systems has yet to begin.

7) Present data used for electrification planning probably overstates the numbers of households with access to electricity. At the same time, the costs of new rural connections are increasing rapidly. Universal access is unlikely to be achieved by 2012 at present connection rates. A new, more realistic policy should be developed that maps out the costs and benefits of expanding access.

8) South Africa's emissions of air pollutants and CO_2 are high and growing due to high energy-intensity and the large part that coal plays in generation. Whether it is cost-effective to reduce the carbon-intensity of electricity generation depends on the future price of carbon. Nuclear power appears uncompetitive against coal at present costs of capital and carbon prices, and this looks unlikely to change.

The underlying institutional structure

The challenges facing Eskom arise partly as a result of the utility's structural and institutional nature. Eskom can be usefully considered in terms of its historical goals, its financial position, its market position and its approach to reform.

In the 1970s and 1980s Eskom over-invested in capacity, regardless of the high cost involved. The current accelerated generation expansion programme runs a similar risk. A strong determination to ensure adequate capacity has its virtues – and there is no doubt that the costs of shortage can be much higher than the costs of excess capacity – but it also needs to be understood that the ownership and governance structure is geared towards overinvestment rather than underinvestment. The move to negotiate goals with government is a welcome step towards imposing a more efficient approach to investment and management, but requires a degree of commitment and expertise on the side of the shareholder that is demanding.

In comparison with privately owned and financed generation companies, where banks and shareholders are encouraged to monitor closely because their own money is at risk, political oversight can too easily become lax and ill-informed. In a competitive generation market, owners can compare the performance of their company against its peers; with a single company such as Eskom such a source of independent information is not readily available to the shareholder.

Financially, the state is not acting commercially as it fails to require Eskom to make an appropriate rate of return, and is effectively underwriting all risks without adequate recompense or risk mitigation (although, admittedly, it has the option of passing on the costs to customers rather than to taxpayers). A relatively low cost of capital – borrowing at favourable rates and funding out of retained profits that are not subject to competitive pressure – makes capital-intensive projects such as pumped storage and nuclear power appear relatively less costly (and hence more attractive).

The consequences of these systemic factors (and post-oil shock inflation) were cheap (in real terms) borrowing and over-investment in the 1970s and 1980s. The resulting substantial excess capacity turned Eskom into a cash cow. In the bargain between the state as owner and the utility's management, Eskom's previously favourable financial position made it possible to combine the state's desire for low electricity prices with Eskom's desire to secure strong political and commercial support from energy-intensive industries and low-income urban and rural consumers.

Eskom's commitment to deliver low-priced electricity to more than 25 major users in energy-intensive industries considered responsible for the country's past economic success leaves government vulnerable should it propose a radical shift in policy. In fact, until recently government appeared to remain enthusiastic about an industrial strategy that relied on a continued capacity to generate large volumes of power from cheap coal, as was reflected in the government-mandated development tariff for energy-intensive users. However, the development strategy needs serious reconsideration, as very cheap fuel is only part of the cost of electricity – the overwhelming share of which is the very capital-intensive investment now required. Higher electricity prices encouraging less consumption would release funds to help stimulate other areas where South Africa is lagging.

The electrification programme undertaken by Eskom, starting in 1994, won wide political support and placed it in a favourable light, in contrast to many poorly performing municipal electricity undertakings. In the 1990s surpluses were used not only to fund electrification but also to under-price wholesale power – a strategy supported by the Department of Public Enterprises (DPE) without any strong intervention from National Treasury.[47]

[47] In recent years, electrification has been funded from capital grants from National Treasury.

The lack of cash constraints and availability of cheap finance might also have encouraged the utility's dalliance with nuclear power, a relatively costly energy source compared to local coal-fired generation. However, pressurised water nuclear reactors are one thing, and advanced research, development and construction of a very expensive pebble modular reactor are quite another. South Africa would seem to have no prior comparative advantage to support the creation of such an energy source. However, the utility might well have regarded the project as a more attractive use of surplus cash than encouraging its owner to seek larger dividend payments.

State ownership and accounting, with its tendency not to act as a demanding shareholder requiring a reasonable dividend, combined with historic cost-accounting (that undervalues assets), a failure to charge an appropriate cost of capital (which, for historic cost accounting, should be a risk-adjusted nominal rate) and outdated (low) estimates of revenue requirements leads to under-pricing as demand tightens. Eskom is well-placed to go to the local capital market, potentially placing it under strain and possibly crowding out other investments (although it is also well-placed to borrow abroad).

In terms of market position, Eskom, as the dominant vertically integrated incumbent, is well-placed to see off any threats to restructure the market. It can easily undermine imports and the entry of independent power producers. Eskom can plausibly argue that independent power producers will demand higher returns, to compensate for market risks. It can also argue that reliance on imports might raise security-of-supply issues that need to be addressed at the political level.

It has been argued that it is in Eskom's interest, as a state-owned enterprise, to delay progress with reforms, resist structural change and attempt to keep control over the investment programme. Eskom vehemently denies this and says that it has actively cooperated in each reform step. It is likely that Eskom management has had mixed views about the creation of a competitive wholesale market and what this would have meant for the utility in terms of its industry and financial position. Given the costs of new power generation and the returns required by the private-sector on investment, the creation of such a market would have pushed prices well above their current tariffs, offering Eskom the prospect of a considerable profit increase, and, consequently, the ability to expand at home and abroad. However, Eskom would also have faced the prospect of losing control over the industry, and strong political/shareholder pressure to hold down its prices, distorting the market.

Conflict over who controls future investment and distractions over where to take the reform agenda have arguably contributed to the pending security-of-supply crisis. At this late stage, the range of reform options has contracted; major reforms should probably wait until supply-security is restored, which could take at least a decade given the lengthy period required to build new coal-fired power plants. Nevertheless, a number of useful and important interim reforms should be made.

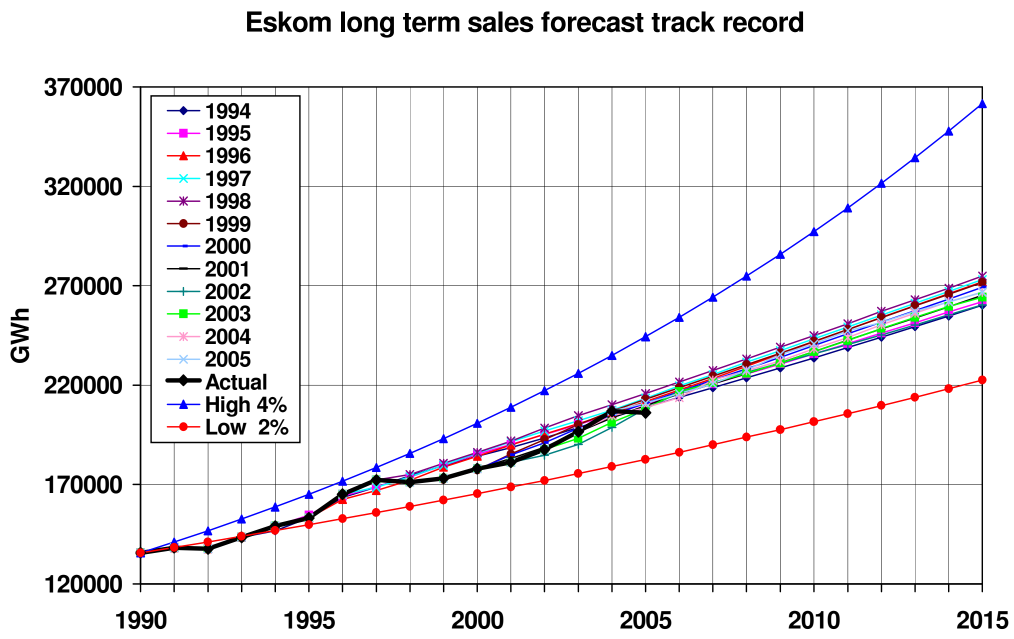
Adequacy of capacity and investment planning

Generation and transmission planning

It has been argued that the present crisis in generating capacity has been caused by economic growth and, consequently, demand for electricity exceeding expectation and predictions. However, historical data do not support the argument.

In recent years, Eskom has been reasonably accurate in its electricity demand forecasts. Figure 35 shows consumption forecasted by Eskom compared with actual consumption.

Figure 35:



It can be seen that electricity consumption growth has fluctuated within a relatively narrow band of about 3 percent a year. Between 2000 and 2006, electricity consumption has grown on average at 3.4 percent a year. Peak demand has grown on average by about 3.6 percent a year since 2000. However, present peak demand is actually lower than that predicted in Eskom's ISEP8, 9 and 10 plans prepared in 2001, 2003 and 2005, respectively. The claim that electricity demand has grown faster than predicted – and that this accounts for presents supply deficits – is not supported by the data.[48]

A second reason advanced for present supply shortages is that the regulator prevented Eskom from building plant by refusing licence applications, disallowing proposed capital expenditure, and awarding price increases too low to enable investment in new capacity.[49] However, the Board of the National Electricity Regulator never refused or unreasonably delayed permission for Eskom to build new generation capacity in the period under consideration.[50] On the issue of tariff increase, the regulator awarded rises lower than those

[48] Accelerated demand growth may well be a factor in the future as growth levels rise.
[49] Such an argument was made by Prof Philip Lloyd – see *Business Day* letter on 29 August 2006.
[50] However, it seems that regulator staff did discourage Eskom from strengthening the Cape transmission line pending the outcome of discussions on contracting an independent power producer to build a combined-cycle gas turbine near Cape Town. In addition, the regulator decided that a reserve margin of 10 percent was optimal; a figure that is probably too low given the age and reliability of most of Eskom's generation plant.

sought by Eskom, but only after a careful examination of Eskom's revenue needs, using credible and internationally accepted regulatory methodologies. Published Eskom statements show that the utility's financial position has actually improved over the past five years. Its profit increased from R2.2 billion in 2001 to R5 billion in 2006. It has maintained a relatively steady return on assets and has been able to reduce its net debt to almost zero. Its balance sheet has placed it in a strong position to finance expansion through retained earnings and low-cost debt.

A third reason given for present supply shortages is that, in the period after the Energy White Paper was published in 1998, government refused permission for Eskom to build new plant since it was seriously considering breaking up the utility and allowing competition and private investment. A cabinet memorandum in 2001 stated that "to ensure meaningful participation of the private sector in electricity in the medium term Eskom is not allowed to invest in new generation capacity in the domestic market".[51] Consultants were contracted to design a power exchange and an electricity trading system. At subsequent meetings between relevant government departments, Eskom and the regulator, a draft agreement was constructed stating that the "Cabinet decision which constrains Eskom's participation in the future domestic electricity growth market should be tempered by the obligation of Eskom to supply".[52] Eventually, in October 2004, the Public Enterprises Minister, Alex Erwin, announced that Cabinet had authorised Eskom to take responsibility for at least 70 percent of new generation capacity requirements. Plans to break up Eskom and introduce an electricity market were abandoned. While independent power producers, with long-term off-take agreements, would be allowed, their contribution would be limited to 30 percent of new capacity.

Notwithstanding the shifting political agenda, Eskom continued with electricity planning and made frequent representations to government and the regulator concerning future generation requirements. It was envisaged that the first additions to capacity would be achieved by the return to service of mothballed plants, contributing about 3 557MW.[53] It was also envisaged that the return-to-service projects (referred to as Simunye) would entail significant black economic empowerment (BEE). Uncertainties on the form that the BEE would take probably delayed the start of work on the first station.

Eskom finally established and resourced a dedicated department to drive the capacity expansion programmes in 2004/05. It returned the first two units of Camden to service slightly behind the schedule set by the regulator (NIRP2). It was a year behind schedule in commissioning new open-cycle gas turbines.

[51] Department of Minerals and Energy Cabinet Memorandum April 2001.

[52] Farm-Inn Workshop, October 2001, later incorporated into a draft agreement entitled "A strategy for implementation of restructuring of the South African Electricity Industry". The third "Farm Inn" workshop between government departments, Eskom and the regulator on 10 March 2004 confirmed the approach. It was confirmed that "Eskom is not allowed to investment in new generation capacity in the domestic market", although under the section "Way Forward" it was stated that the "obligation to supply currently lies with Eskom but is affected by the Cabinet decision that does not allow Eskom to build new generation plant. The obligation to supply requires that certain costs and obligations must be incurred to ensure that South Africa has sufficient generation capacity. Eskom and the NER have reached a solution whereby Eskom is allowed to incur costs for new build on the basis that they are ring-fenced and may be transferred to an independent developer at any stage in the new build process."

[53] Eskom ISEP7, 8, 9 and 10

A fourth reason advanced for the present tight demand/supply situation is that government's programme to procure private power is behind schedule. A Cabinet decision in December 2003 authorised the DME to tender new generation capacity on the open market. In February 2004 the department sought bids for legal and technical advisers to support the tendering process. It was envisaged that the advisers would be appointed by the end of March 2004, potential project sponsors would pre-qualify by September 2004, project bids would be presented by April 2005, the successful bidder would be notified by July 2005 and negotiations with the successful bidder would be concluded by November 2005.[54] In practice, the department released a request for qualification only in April 2005, later announcing that five consortia had qualified as bidders for about 1 000 MW of open-cycle gas turbines to be built in the Eastern Cape and KwaZulu Natal. In the end, only two bids were received. The delays have been partly caused by Eskom, which has raised concerns around regulatory risk (i.e. whether the regulator in the future could block the full cost of the power purchase agreement being passed to customers). Concerns have also been expressed about the security of fuel supply to the open-cycle gas turbines. DME eventually announced a preferred bidder, AES, but after many months negotiations collapsed.

A fifth reason given for the present power shortages is inadequate planning. Parallel planning processes are run by Eskom and the electricity regulator. Every two or three years Eskom updates and revises its ISEPs. This involves updating demand forecasts and developing a least-cost, risk-adjusted, set of supply and demand-side options. ISEP8 was undertaken in 2000/01, ISEP9 in 2003, ISEP10 phase 1 in 2005, ISEP10 phase 2 in 2006 and ISEP11 in 2007/8. Meanwhile, the National Electricity Regulator (now NERSA) produced NIRP1 in 2001 (based on a version of Eskom's ISEP8). NIRP2 was produced in 2003/04 with Eskom's assistance but using public-domain data and under the governance of a regulator-chaired advisory and review committee, which comprises invited stakeholders. After great delay, work has recommenced on NIRP3, undertaken by international consultants under the guidance of the advisory and review committee. NIRP3 was due for completion in 2007, but will only be published in 2008.

The ISEP9 base plan (seeking a 10 percent reserve margin) envisaged that Camden's first unit would need to return to service by 2007. An open-cycle gas peaking plant would have to be up and running by 2006. Preparatory work would have to commence on the Braamhoek pumped storage scheme. A decision would be required by the end of 2004 on whether a new base-load power station should be built and brought on line for 2011. Combined cycle gas turbines at Coega and in the Western Cape were also seriously considered. ISEP9 also presented an accelerated plan, which outlined the capacity expansion schedule necessary to maintain a 15 percent reserve margin. In effect, all build and commissioning would have to be accelerated by about two years: Camden should start coming on line in 2005, the first open-cycle gas turbines in 2006 and the first base-load coal fired plant in 2009. Given the envisaged lead times for the projects it was implicitly accepted that a lower reserve margin was inevitable. The differences between the two plans are indicated in Figure 36.

[54] Department of Minerals and Energy: Call for proposals and terms of reference. Project: Legal and technical advisors to assist in the tendering for new generation capacity in South Africa. February 2004.

Figure 36: Comparison between ISEP plans with different reserve margins

ISEP9 base case (moderate growth, 10 percent reserve margin)	**ISEP9 accelerated plan** (high growth, 15 percent reserve margin)	**Planned capacity**
2007	2005	Camden RTS (2 units/year) – 1 520MW
2008	2006	Grootvlei RTS (2 units/year) – 1 130MW
2009	2006	Komati RTS (2 units/year) – 906MW
2011	2009	Base-load (gas, coal, imports) – 1 200MW
2012	2012	Braamhoek (2 units/year) – 1 332MW

The electricity regulator's NIRP2 risk-adjusted preferred plan 14, approved by the advisory and review committee, indicated that the first two units of Camden should be brought into service in 2005 and a further two in 2006 (with the rest of mothballed plant brought on line before 2011). The plan called for 720MW of open-cycle gas turbine peaking plant to be brought online by the beginning of 2006. The plan also envisaged that a new base-load station (fluidised-bed coal plant) should put into operation by 2012. The reserve margin of this plan would be between 13 percent and 15 percent for most years, although a slightly higher percentage in 2005-2008.

In other words, the present supply squeeze has been long foreseen. The 1998 White Paper predicted that electricity demand would exceed generation capacity in about 2007 and specified that an investment decision in new capacity would need to be made by the end of 1999.[55] The electricity regulator has raised with government the urgency of making new investment decisions.[56] Independent analysts have also warned publicly of the looming power crisis.

Eskom was able to bring the first Camden Unit into commercial operation in July 2005, and the next in 2006, slightly behind schedule. Since The full 3 557MW of mothballed plant was due to be returned to service before 2012, but this programme has been accelerated and completion is now scheduled for 2010. In June 2005, Eskom also approved investments in open-cycle gas turbines and a new coal fired base-load plant.

Electricity plans developed during 2001-2004 have not been fully realised. Additional peaking plant in the Western Cape would have alleviated the recent supply constraints there. However, the national load-shedding of 18 January 2007 would still not have been avoided – as the deficit between available capacity and demand was larger than could have been filled by the peaking plant being constructed at Atlantis and Mossel Bay.

The various plans appear to have underestimated the risk of ageing plant and, perhaps, inadequately maintained plant incurring unplanned outages. Present plans assume an energy availability of 86 percent compared with the 89 percent assumed in ISEP9. Planned reserve margins were too low – 10 percent rather than 15 percent (although, in this respect, planners had little room for manoeuvre given the long lead times required to build base-load plant and the delays in investment decisions in the early 2000s). Assumptions on the availability of

[55] Department of Minerals and Energy: White Paper on Energy Policy for the Republic of South Africa, 1998.
[56] See for example, the electricity regulator's Position Paper on Future Generation Capacity, submitted to the Minister of Minerals and Energy in July 2003.

non-Eskom plant were too high (2 615 MW was assumed available in ISEP9, but, as of 2007, less than 1 378MW was available.) The figure used for the cost of unserved energy was almost certainly too low: R20 000/MWh compared with the figure of R75 000/ MWh that used in 2007. The load curve has also flattened more than expected, shortening the periods available for maintenance.

In summary, the present tight supply demand is partly caused by inaccurate planning assumptions. However, it is also a function of policy uncertainty in the period 2001-2004. Mixed messages were sent to Eskom concerning its responsibilities for investing in new capacity. Investment decisions were delayed, including urgently needed ones to resource and rebuild capacity, and to plan and build big new generating plants. Delays in committing to independent power producers have also been felt.

The need for improved coherence and coordination in electricity planning

The Integrated Energy Plan developed by the Department of Minerals and Energy, and the National Integrated Resource Plan, developed by NERSA, appear to be largely irrelevant to Eskom's electricity planning.

Improved coordination and integration between government's, the regulator's and Eskom's plans could help to lessen the risk of contradictory decisions being made at a time when security-of-supply concerns are paramount. The lack of planning coordination has raised a number of issues.

1) It appears that neither Eskom nor the regulator were involved in, or informed of, a memo presented by the DME to the Cabinet requesting and gaining permission in 2006 for the department to run a competitive open-market tender for combined-cycle gas turbines at Coega in the Eastern Cape. The huge escalation in the price of LNG in the past two years has since made the project a less attractive option. In the light of this and the delays that the department has previously experienced with such tenders, Eskom continues to plan for all contingencies, including the likelihood that the Coega plant will not materialise. The confusion creates great risk since increased base-load capacity is needed before the coal units start to come on line in 2012.

2) Eskom's licensing application for the "Gas 1" project (which will double open-cycle gas turbine capacity at Atlantis and Mossel Bay) was questioned by the electricity regulator. However, Eskom had already placed the order for these turbines and originally planned to commission them by 2008 (now 2009). Both the DME and the regulator were concerned that the investment does not appear in NIRP2 (which was regarded as the government's official plan).[57] However, Gas 1 does appear in Eskom's ISEP position plan. Similarly, a number of new coal-fired, nuclear and wind plants, which do not appear in the regulator's plans, are in the process of being approved by Eskom's board and the DPE.

3) The issue of energy imports and exports and cross-border cooperation requires comprehensive planning. The Southern African region offers a range of attractive energy sources, including those provided by coal in Botswana, gas in Namibia and hydro in Mozambique, Zambia and the Democratic Republic of Congo. Investments in large regional generation projects could make a powerful contribution to regional economic development. However, technical and political risks need to be assessed for each import corridor, including

[57] However, NIRP2 does make provision for 2 640MW of open-cycle gas turbines before 2011

the implications for regional network integration and stability, standards, wheeling, costing principles and national security of supply. An explicit policy is needed on the prudent or maximum level of imports and the mechanisms whereby imported power might become part of the planning and investment framework in South Africa. A related issue concerns electricity exports. The level of electricity exports from South Africa more or less equals the amount that is imported (mostly from Cahora Bassa in Mozambique). Although it amounts to only 6 percent of Eskom's total electricity sales, six of South Africa's neighbours are heavily reliant on the supply to power their economies. As South Africa struggles to meet its own needs, a review of Eskom's cross-border contracts is being sought. Eskom needs to be guided on the issue by government policy and an acceptable integrated regional electricity plan.

4) The need for more agile plans that can quickly respond to changing costs and risks has been identified. Electricity-generation investments tend to be capital-intensive and lumpy, with long lead times. Eskom already faces great risks in terms of the timing of its investments.[58] Regulator and government planning and approval processes should not compound the risks.

5) Capacity constraints in government and the regulator appear to require that the planning processes be brought together. It makes sense to rely on the best resourced and most detailed planning process – Eskom's. However, effective governance and oversight needs to be promoted to ensure that Eskom's planning assumptions are in the national interest and incorporate the perspectives of a wide range of stakeholders. It is also important that electricity plans are published and open to public scrutiny and comment. Eskom often argues that the publication of data could prejudice the commercial interests of its customers or its negotiations with suppliers. However, such data are routinely and safely published in other countries. [59]

Eskom continues to dominate South Africa's electricity market. However, government policy states that up to 30 percent of new generation capacity will be provided by private participants. In this hybrid market, it is vital that government takes the lead in ensuring a coherent, integrated framework for electricity planning and investment decision-making.

The need for improved coordination and efficiency in investment decision-making

The Public Finance Management Act requires Eskom to seek approval for investment decisions from its shareholder. This generally happens within the stipulated period of 30 days – and generally before Eskom seeks licensing approval from the regulator.

The Electricity Regulation Act (2006) requires licence applications for generating plant to include "evidence of compliance with any integrated resource plan applicable at that point in time or provide reasons for any deviation, for approval by the Minister". Generally, NERSA and the DME consider the NIRP3 to be the official integrated resource plan. However, it is already behind the times (due to outdated planning assumptions) and is very different to the

[58] Based on present strategic thinking in Eskom, it is anticipated that a further 40GW of plant, in addition to the existing 40GW, will be added in the next 20 years. The primary emphasis will be on "big coal" and "big nuclear" with multiple orders being placed with suppliers in order to benefit from economies of scale, standardisation, increased local content etc. Risks will be addressed mainly through unit size, accelerating or decelerating the build programme, timing of decommissioning, levels of imports, etc. In this context, electricity planning will be conducted very differently in the future.

[59] See, for example, the international review incorporated into Duncan Wilson and Ivan Adams's report to the Department of Public Enterprises: A Review of Security of Supply in South Africa. July 2006.

plan now being followed by Eskom and the DPE. The licensing process may slow down as the regulator seeks to interpret the provisions of the 2006 act.

The Electricity Regulation Act also empowers the energy minister, who “may, in consultation with the regulator, determine that new generation capacity is required to ensure the continued uninterrupted supply of electricity”. The minister “may make regulations regarding new generation capacity and the types of sources from which electricity must be generated and the percentages of electricity that must generated from such sources”. The minister may also “require that new generating capacity must provide for private participation”. The act also gives the minister powers to organise tenders and procurement of new generation capacity. While the phrases “electricity security” or “security of supply” do not appear in the act, its provisions have been interpreted as giving the minister responsibility for security of electricity supply.

However, in practice, it is Eskom that takes responsibility for most investment decisions, notwithstanding the energy minister’s powers and responsibilities under the act – and their exercise in relation to the tender at Coega and that for independently supplied open-cycle gas turbines.

The investment decision-making and approval processes that are spread between Eskom’s Board, the DPE, the National Electricity Regulator and the DME need better coordination.

Governance and institutional challenges

The challenge for the government and the regulator is to ensure that Eskom delivers its part of the investment programme in a timely, cost-effective manner, and that it cooperates with independent power producers and foreign investors (for example, at Mmamabula in Botswana). The main challenge is that of information asymmetry – the DPE, the National Electricity Regulator and the DME lack the information to adequately analyse Eskom’s preferred investment plan, and run the risk of delaying urgent decisions if they try to become better informed.

The first two coal-fired investment options are a done deal. However, the choice of Mmamabula might not be so obvious and its PPAs might take time to negotiate. Furthermore, significant transmission investment is implied by the coal-fired choice. As for the choice of peaking plant needed in the Cape, LNG, base load combined-cycle gas turbines, and nuclear power (pressurised water reactors or pebble-bed modular reactors) are all problematic.

Similarly, deciding on the right mix of price increases and borrowing to finance the investment programme is not simple. A strong case can be made for raising marginal prices to scarcity levels to encourage demand-side management, and for escalating Eskom’s average prices towards the LRMC (with borrowing to finance the gap until the higher cash flow from the new prices can shoulder the burden of investment, maintenance costs and debt repayment. The system of multi-year price determination means that durable pricing decisions have to be signalled in advance. In other words, much careful consideration is needed.

Distribution

Distribution is split between Eskom and municipal companies, or munis, of which there are 177 (down from more than 400).[60] In 2004 Eskom sold 126TWh to its 3.6 million customers. while municipal and other distributors sold 83TWh to their 4 million customers.[61]

Threats to security and quality of supply

NERSA requires all distributors to report annually on a range of performance indicators. However, only a few municipalities actually measure and monitor security and quality of supply, and reporting to the regulator is poor. The regulator conducts rolling annual audits of 30 to 40 distributors to assess their compliance with licence conditions. The audits show that many distributors lack proper maintenance policies or plans.[62]

NERSA commissioned an independent technical audit of 11 of the largest electricity distributors (nine municipalities and two Eskom regions). The two Eskom regions achieved by far the best ratings. The audit found that the municipalities (with the exception of eThekwini) needed to improve their network reliability, controls, and refurbishment planning and maintenance.

The audit said that the high-level findings "reflect the generally held views of the industry in regard to lack of investment and skills", particularly in municipalities. The audit observed a "lack of investment since the advent of the EDI restructuring hiatus". Governance and management was perceived as too intrusive, reflecting a lack of ring-fencing between municipal electricity departments and other council activities. While base networks were generally well-designed, "investment in the refurbishment and maintenance processes is insufficient". There was a "continual loss of skills and [there were] only limited efforts to train and develop new staff". The networks of smaller municipalities, in particular, were observed to be "in a poor state of repair and there are … instances where basic contingency requirement are not met. Staff are demotivated and often under-skilled for the requirements of the job. Very few formal systems are in place for the management of the maintenance process." By contrast, Eskom distributors were found to be "well run and managed undertakings". They had "excellent and comprehensive management and maintenance systems [as well as] adequate funding for both maintenance and refurbishment, adequate staffing at all skills levels, and access to sound and competent technical expertise".[63]

The audits indicate deteriorating supply security among municipal distributors, caused by inadequate and overdue investment in physical capital (maintenance, refurbishment and system strengthening) and human capital (resulting in a skills shortage).[64] The root cause of the lack of investment is the uncertainty that continues to surround distribution-sector restructuring, which has been talked about since the ANC Electricity Conference in 1992. A number of bodies have been formed to restructure the sector: the National Electrification Forum, the Electricity Working Group, the Electricity Restructuring Inter-Departmental Committee, and the Electricity Distribution Industry Holding company. A major study was commissioned: the PricewaterhouseCoopers blueprint report. A number of Cabinet decisions

[60] Storer and Teljeur (2003).
[61] NER *Electricity Supply Statistics for South Africa, 2004.*
[62] See for example a report to the electricity regulator's board on 26 October 2005 entitled: Municipal Distributor's Compliance Audit.
[63] Mertz and McLellan report to NERSA: Independent technical audit on eleven electricity distributors networks – June 2005.
[64] Ibid.

have been made. However, no concrete progress has been made towards the establishment of the RED companies that are supposed to amalgamate Eskom and municipal distributors.

All major stakeholders in the sector, with the exception of the Department of Minerals and Energy, recently expressed misgivings about the lack of planning and specificity in setting up the REDs, including a lack of clarity on a range of unresolved issues such as shareholding, asset transfer and levies. With one exception, all the stakeholders expressed scepticism about whether any real progress would be made towards the establishment of these companies unless government amended the constitutional provisions that give municipalities sole rights over electricity reticulation. The unresolved dilemmas, and their implications in terms of under-investment, endanger supply security.

Restructuring process

Most municipal distribution companies purchase all their power from Eskom and then sell it to local consumers, taking responsibility for the distribution and retailing functions. Reliability and prices vary widely.

Internationally, it is not uncommon for electricity distribution companies to be municipally owned, as they are, for example, in Germany, Norway, and the Netherlands. If electricity is cheap (from local hydro, as in Norway) or customers are rich (as in Germany) local munis are able to make sufficient profits to fund municipal activities and maintain the network in good repair. Electricity is, after all, so valuable that most consumers, even in middle-income countries, consider the price they pay good value, even if it is higher than it needs to be. Pressure to reform can therefore be weak.

In South Africa, the pressure to reform the municipal distribution companies is prompted by concerns about their ability to deliver efficient and reliable power to their customers. These, in turn, are prompted by concerns about the effectiveness of municipal governance (and the hurdles that this places in the way of proper financing). Distribution companies are attractive to municipalities for several reasons. Since electricity has a high value-cost ratio compared with other services such as water, public transport, waste disposal etc, it represents an attractive source of revenue. This revenue may be used for electricity cross-subsidies or for other municipal activities, leaving vulnerable the adequate maintenance and management of the network. As the assets have long lives, the municipalities may fail to notice their gradual deterioration and the loss of experienced engineers. In addition, municipalities tend to like the bargaining position that electricity distribution confers – threats to switch off the power might induce customers to pay other bills due to the municipality.

Some munis have recognised the need for action to support the quality of local electricity supply. In others appropriate action is not being taken and the quality of supply is deteriorating. Staff vacancy levels often are running between 20 and 50 percent and staff quality is declining. Some munis have a policy of not filling vacant positions in order to release funds for other purposes.

The case for restructuring is founded on the argument that the distributors need to be insulated from local politics, where the variety of objectives mitigates against a clear mandate to deliver reliable supplies of electricity at least cost while ensuring financial viability. After lengthy discussions starting in 1992, and advice from consultants, the Cabinet settled on the concept of six REDs covering the entire country and comprising Eskom's distribution regions plus the munis. The government set up the Electricity Distribution Industry (EDI) Holding

Company in 2004 to implement the plan and, in July 2005, set up the first RED, in the Western Cape, which was later dissolved.

In October 2006 the Cabinet approved a plan to create six "wall-to-wall" REDs as public entities to be regulated in accordance with the Public Finance Management Act and the Electricity Regulation Act. Cabinet also approved that Eskom become a share-holder in the REDs, but only for a limited period in order to avoid entrenching vertical integration between generation, transmission, distribution and retailing. However, there is a stumbling block – any municipality can resist joining the scheme by arguing that, under the Constitution, it cannot be forced to give up its distribution activities.

The Cabinet's preferred option of six REDS

The existence of six distributors would allow each to achieve economies of scale and financial viability, to attract competent staff, to permit benchmarked regulation, and to be large enough to attract private-sector participation. Each RED would have, on average, more than 1 million customers. One of the arguments for such REDs is that if they were granted a degree of commercial autonomy, and required to install better metering and asset registers, they could be subject to more effective regulation. The power that the municipalities would lose under such an arrangement could be greatly restored by granting them the power to levy taxes on and provide subsidies to electricity consumption, although there may be a case for limiting the extent to which industrial and commercial consumers could be taxed.

Whatever its advantages, the RED solution has received less than full support from municipalities and Eskom, both of which would need to agree to transfer assets and staff to the new distributors for the programme to work. Asset transfer can be fraught; establishing a proper asset register and valuing its present state tends to cause arguments when it is the value of the various parties' contributions that determines their final shareholding. Transferring staff can also cause problems when the wage rates differ so markedly between Eskom and munis (although, in the past, Eskom has successfully absorbed staff).

Unless all parties reach agreement, complainants can appeal to the Constitutional Court, which would probably confirm that reticulation (interpreted as distribution and retailing – following the Electricity Regulation Amendment Bill) is a municipal responsibility. Such an outcome would delay the process, exacerbate present uncertainty about the fate of assets and staff, and encourage continued neglect of maintenance and loss of key personnel. Without an amendment to the Constitution, the restructuring will have to be voluntary (and will probably be slow). The Electricity Distribution Industry Restructuring Bill project team has laid out a possible approach.

A gradualist approach to six REDS

Given present constitutional constraints, the goal of six REDs can probably only be achieved by adopting a gradual, persuasive approach. A first step would be to restructure Eskom's distribution division into six embryonic REDs. Since the REDs are destined to be public entities regulated under the Public Finance Management Act and the Electricity Regulation Act, they each must be more than 50 percent state-owned (directly or via Eskom). Each one will need to be adequately endowed with assets and cash reserves, such that its regulated revenue would enable it to stay financially strong and creditworthy. Sooner rather than later, Eskom will be required to relinquish its ownership in the REDs to avoid increasing its already extensive vertical integration through all stages of the industry.

It would be possible to start unbundling the electricity-supply industry by legally separating Eskom's distribution division from its parent, creating a holding company for the Eskom REDs owned directly by the state (through the DPE). After the company had secured adequate financial and human resources, the REDs would invite the munis to join them, making good the shortfalls in asset quality of any munis they thus acquired (the failing munis would probably be the first to approach). Later, the individual companies would be divested from the holding company and the shares transferred to the DPE, allowing for potential private-sector participation. (The promise of such participation might persuade some munis to sell their assets in order to realise a useful cash windfall.)

The REDs or their holding company would be responsible for persuading municipalities to assign their distribution assets to the new enterprises in exchange for shares. The project team working on the Electricity Distribution Industry Restructuring Bill notes that valuing the contributions of munis and Eskom could cause problems in the absence of an objective measure of their relative shares. It proposes past electricity sales, with muni ownership capped at less than 50 percent. The state could contribute shares to enable the ownership constraints to be met. These shares could, if necessary, be financed by issuing debt, which would be paid down out of the state's dividends from the venture. A cash injection (from the state's shares, possibly from issuing debt) would be made available to finance the investment needed by the enterprise. Since the munis probably would not all join at once, the cash would be injected gradually as investment needs arose.

A range of inducements could be put in place to encourage a municipality to transfer its assets (or to subcontract for the REDs to manage its networks and employ its staff). One would be to grant large customers the right to take supply direct from the RED grid, perhaps requiring them to pay for the connection assets to the higher voltage RED grid in non-RED areas. If large customers were legally free to contract directly with the local RED, then the muni might lose its better customers. Such a change in the terms of the electricity market would weaken the municipality's financial position, as a result of which Eskom might need to impose more onerous terms for late payment (perhaps including the requirement for advance deposits in an escrow account to cover possible bad debts). The new economic reality might force the muni to charge its remaining customers a higher tariff, or remove some of the cross-subsidies. The muni would then be presented with a clear incentive – if it joined the RED, its customers would (largely) enjoy the same terms of supply that they used to enjoy and, in time, experience an improved service. Such an example could pressure other munis to follow suit, or to improve their distribution performance to the point that joining an RED would be unnecessary.

Another method of encouraging munis to join a RED (or improve standards) would be to require all distribution companies to compensate consumers for supply interruptions (as happens in the UK). The regulator would specify service standards and penalties for failures to meet them, to be paid to consumers. The revenue to cover such payments would need to be recovered from higher average tariffs, but customers would, on average, be no worse off. The distribution company would have an added incentive to improve service or join a RED with better management.

Another route into REDs might be to have an administration procedure for a failing muni that would transfer it to the distributor. Better public access to information about the quality of service and prices in different munis, combined with examples of successful RED-managed munis, might allow voters to press for improvements.

The issue of asset valuation at the time of joining a RED has been identified as the most serious obstacle facing the gradual approach to their establishment. If muni shares are issued solely in proportion to past sales then there is no incentive for the muni to maintain its assets, which will rapidly deteriorate, burdening the RED financially. The project team's solution is to penalise in proportion to asset-quality deterioration. An alternative is to roll forward a regulated asset base from day one, both for the RED and the munis, starting from a notional value based on past sales. If the muni then underinvested or failed to maintain the assets, its regulated asset value would decline relative to the RED's overall regulated asset value, and so would its claim on the shares to which it had been entitled.

In general, the main disadvantage of pursuing a large scale rationalisation of the industry – such as that embodied by the six-REDs plan – is that it can be institutionally disruptive. Creating new institutions with robust governance, management and administrative systems is not easy in a country that has a skills shortage. Political appointments to the boards and management of the new REDs might undermine their effectiveness. Poorly governed and managed REDs would be likely to continue losing experienced staff and would struggle to make up the backlogs in maintenance and investment. The net effect could be to compromise rather that enhance security of electricity supply. Such risks could be overcome if the new REDs were developed incrementally from Eskom's six distribution regions so that maximum use was made of Eskom's superior systems, management and assets, as well as its skilled and experienced staff. However, the large munis oppose such a plan.

An alternative to the REDS

Twelve of the largest municipalities account for about 80 per cent of electricity distributed by all municipalities. An alternative to the REDs system could be to allow them to retain their electricity businesses and to provide them with intensive and sustained support to develop ring-fenced, corporatised, effectively regulated and well-managed utilities, with adequate investment in physical and human capital.

In this model, the large corporatised muni distribution companies would take over Eskom's distribution assets, staff and systems within the municipality boundaries, while the six Eskom distribution regions (no longer wall-to-wall) would deal with rural and failing munis, leaving middle-sized munis to decide whether to join. Financial inducements or local consumer pressure might persuade them to do so.

The model has the advantage of having the full support and hence potential participation of most distributors. Eskom and the twelve largest munis account for more than 90 per cent of the distribution industry. Policy uncertainty around large scale restructuring would disappear. The major players would be allowed to keep their electricity distribution businesses.

However, the model has its risks – not least the challenge of developing robust and effective governance systems for the large muni distributors. City Power Johannesburg (Pty) started along this route before 2001. It has now formalised a governance structure, in which the council, as shareholder, receives dividends, sets standards and policy, and approves tariffs and business plans, while the company concentrates on delivering a high-quality service to its customers. Since the national regulator is also involved in setting standards and regulating distribution, the potential for conflict between shareholder and regulator has arisen. In addition, the company has encountered conflicts between the council's objectives and the enterprise's need to collect adequate revenue.

A further problem is that City Power has had to manage five non-integrated networks. This has tested its leadership capacity, given a shortage of suitable managers, poor data and little past history from which to learn in order to make realistic plans, and extraordinary human-resources challenges (new job grading, pension liabilities, and all the staff issues involved in merging disparate business activities). Other municipalities would be likely to face similar challenges, all of which would probably take many years to address satisfactorily.

For the model to work, amendments to the Municipal Finance Management Act and the Municipal Systems Act would need to be considered to insulate muni distributors from intrusive political interventions, and micro-management by municipal staff. A clear division of roles and responsibilities would need to be established: the national regulator's responsibility for setting tariffs and service standards; the councils' role as the owner of assets; and the council's political role in relation to electrification policies and pro-poor subsidies. The Electricity Regulation Amendment Bill is ambiguous on the power of the regulator to set municipal tariffs: it makes provision for the minister to establish "norms and standards" for regulating electricity reticulation. The approach cannot substitute for effective economic regulation, which should be founded on a thorough understanding of the costs of individual utilities, and incentives to improve efficiencies.

As a separate issue, large customers (for example, those who consume more than 100GWh a year) would be able to choose their supplier – Eskom or the munis. If Eskom had been obliged to transfer their grids within municipal boundaries to the municipal distribution companies, then direct connection to the Eskom grid would no longer be feasible except for those taking supply at very high voltage. However, Eskom would still be able to offer retail supply via a regulated wheeling charge on the muni's network.

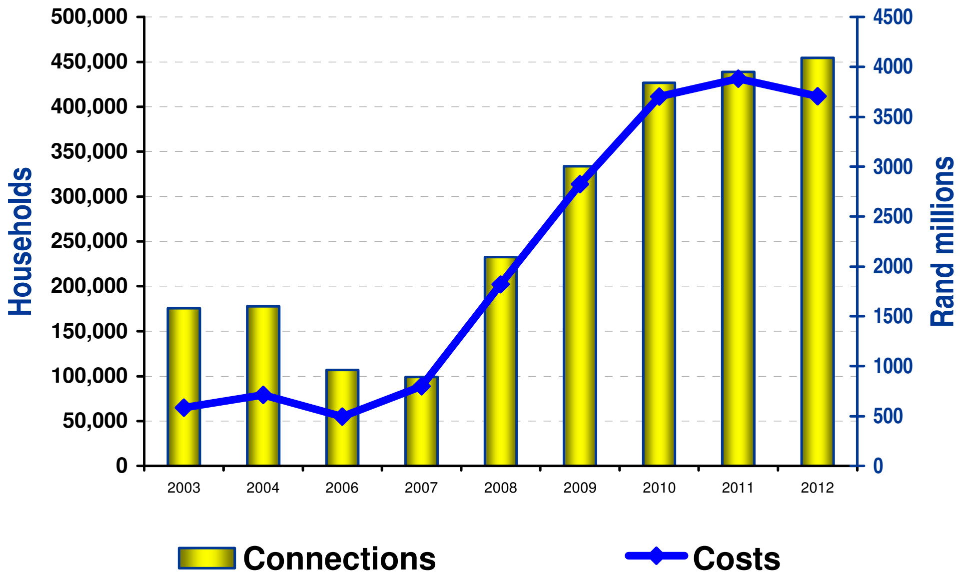
A potential disadvantage of this model would be continued disparities in pricing. However, the electricity regulator would have great opportunity to benchmark distribution companies and create regulatory incentives to encourage efficiency. Another potential disadvantage might be the continued existence of distributors of the wrong size. However, it should be noted that, at present, a number of the medium-sized munis appear to be providing a more than adequate service. Those that failed to do so would be encouraged to join either the large city distributors or Eskom. The problem of voluntary mergers would still exist. However, in contrast to the REDs model, the problem would be contained at the level of the smaller, poorly performing munis which, at least in theory, would have the biggest incentive to sell or hand over their (loss-making) electricity distribution businesses.

The model has the advantage of being the least disruptive of the restructuring options, probably posing the least threat to security of supply.

Electrification

Government has stated that it wishes to achieve universal access to electricity by 2012. However, there are no realistic plans in place to achieve the goal. Figure 37 indicates the number of connections required and the investment needed to achieve the goal.

Figure 37: Connections and costs to reach universal access



The modelling is probably based on optimistic assumptions on the present level of electrification. This report has pointed out that some of the present planning estimates are based on faulty household numbers and that data derived from cumulative new connections do not tally with census figures, which might include illegal connections. Present estimates of the proportion of households with access to electricity range from 57 to 78 percent.

The challenge of achieving universal access is exacerbated by the increasing cost of connections as the electrification programme reaches rural households further and further from the grid. In the past, average costs of connection (and the level of the capital subsidy made available by government) were less that R3 500. Latest estimates for rural connections estimate the cost at more than R10 000 per household.

Electricity pricing and industrial policy

Past and present industrial policy appears to support heavy and electricity-intensive resource-based industry through low electricity prices and cheap coal. In addition, South Africa maintains a fuel-independence strategy through Sasol. However, Sasol imposes heavy demands upon coal and gas supplies and makes heavy claims on any future carbon budget. The company's pre-emptive use of imported gas might restrict the availability of the fuel for electricity generation.

Given South Africa's large cheap coal reserves, it probably makes sense to use low-quality coal with a low mine-mouth export value for electricity generation. The fuel source compares favourably with LNG and nuclear power at any plausible carbon price. Large coal-fired power stations are relatively inflexible in economic terms, in that the opportunity-cost of generation falls to the variable cost (or less, if start-up costs are significant and demand falls below the minimum generation level) and this will be very low in many places (possibly as low as R10-40 per MWh.

Low priced base-load electricity is therefore to be expected. Competing with cheap hydro for aluminium smelting is, however, by no means guaranteed to be advantageous. Heavy and electricity-intensive resource-based industries confer no apparent external benefits and some fairly obvious external costs (pollution, notably from CO_2, and Dutch disease-type problems from external resource-trade dependency). No good case can be made for subsidising industrial electricity. The prospects of creating unskilled jobs in these industries (particularly aluminium) are likely to be poorer than elsewhere in the economy (commerce, trading, light industry). In addition, overall growth plans would be well-served if the balance between light-industry and the service-industry on one hand, and heavy industry on the other, was redressed.

Compared with the country's relatively low cost of base-load power, peak loads are quite likely to be more expensive in South Africa than they are in other countries (particularly those with storage hydro or local gas). The cost difference should be reflected in the electricity tariff, which should introduce suitable time-of-day short-run marginal cost pricing, and system-simultaneous peak pricing for the fixed costs of generation and transmission. Peak prices might need to be 20 times the cost of off-peak summer power. Load shifting incentives such as ripple meters for smaller consumers and hourly metering for larger customers would be necessary to deliver such a highly differentiated hourly tariff structure.

If Eskom set economically efficient bulk supply-and-transmission use-of-system charges, then its marginal prices in many hours would substantially increase, particularly as demand became tight relative to supply and the length of the high-priced peak increased. This would probably increase Eskom's profits above the allowed regulated total revenue, raising the question of what to do with such surplus profits. One option would be for Eskom to keep them for investment purposes (reducing borrowing) or to transfer them as dividends to the owner. That might reduce Eskom's incentive to eliminate tight demand and hence lengthy periods of high-scarcity prices, although such problems might be dealt with through negotiated goals set by the shareholder.

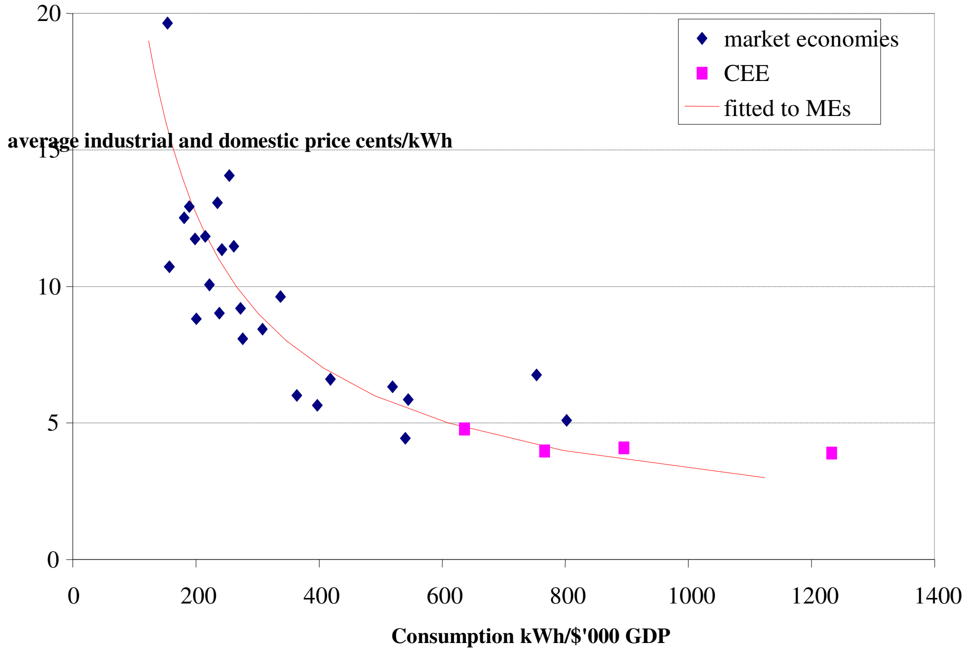
Another alternative would be to move to cost-reflective average prices over a transitional period, effectively transferring the notional surplus from pricing efficiently to consumers. Such funds (effectively rebates) should be returned in the least distortionary way possible. The aim should be to encourage demand reduction, particularly at the peak, although not during off-peak hours. The solution could be to adopt high peak prices for those on hourly meters and high peak-season prices for those on simple meters, combined with a reduction in fixed charges. New large consumers should be offered contracts with high total charges for the next few years, until the reserve margin increases to acceptable levels, and lower prices (for base-load power) thereafter, perhaps encouraging them to defer but not abandon investments. Zonal or regional price differences might need to increase for energy and connection (but not for fixed charges for existing customers); although, where it is clear that these are likely to change in the future with new investments, forward indications and, possibly, contracts should be provided. Domestic customers should face higher energy charges (perhaps above a life-line level) and lower fixed charges, which has the advantage of being more efficient while protecting poorer consumers.

The case for what is in effect subsidising electricity needs to be considered carefully. It does not necessarily constitute a default option, but rather a choice with significant and, arguably, unattractive implications for South Africa's development strategy in the coming decade.

Energy efficiency, demand-side management and environmental concerns

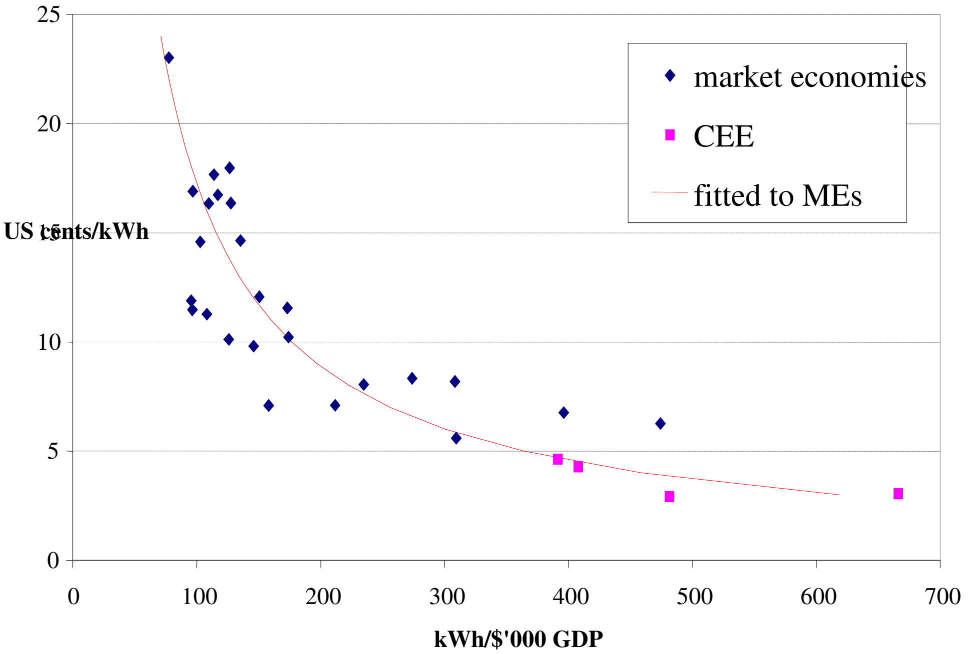
Low prices contribute to excessive electricity use, as Figure 38 and Figure 39 illustrate.

Figure 38: Relationship between consumption and price



Source: *International Energy Agency Energy prices and taxes, IEA Energy Statistics*

Figure 39: Relationship between non-industrial consumption and price



Source: *International Energy Agency Energy prices and taxes, IEA Energy Statistics*

Persistent differences in electricity prices across countries appear to be associated with systematic differences in electricity intensity. Prices appear to affect electricity intensity, at least in the long run when industrial structure and investment has had time to adapt to new prices. Demand-side management has an important role to play in tight markets (i.e. over the next decade), particularly when electricity is underpriced and reliability is not properly charged for. Water heating and air-conditioning are particularly susceptible to demand-side management strategies – time-shifting with ripple or other metering can be very cost effective at avoiding peak loads when the scarcity price (but not the tariff charged) can be very high.

Eskom has already developed two demand-side management programmes (its coordinated municipal control system and its flexible load hot-water control) that prevent water-heating loads during peak hours, and which are capable of shifting 180MW at the morning peak.[65]

If demand eventually responds to price signals, then it becomes more urgent to start signalling the need for higher prices as soon as possible. The case has been made for moving existing industrial and commercial users to LRMC prices quickly, perhaps with transitional contracts, and for confronting new consumers immediately with the costs of new independent power producers. Otherwise, there is a danger that South Africa will remain locked into a development strategy that encourages capital-intensive industry with a limited demand for unskilled labour, whereas what would seem to be needed is a vibrant economy with good communications infrastructure to encourage labour-intensive and service-sector expansion – in pursuit of which the price of electricity would appear to be of relatively low significance.

Coal-fired electricity generation is a major source of air pollution. The coal used in electricity generation is lower quality than that which is exported and contains roughly 0.9 sulphur and 30 percent ash. Normal air pollutants are covered by environmental standards for emissions from new plant. Carbon dioxide is subject to a shadow price in planning (the Clean Development Mechanism benefit).[66]

According to the US Energy Information Administration, in 2002 South Africa accounted for more than 90 percent of Africa's CO_2 emissions, while accounting for only about half of its total electricity generation and only 35.6 percent of total primary energy consumption. Since 1993, CO_2 emissions from coal have been growing by 2.8 percent a year. Eskom accounts for 56 percent of coal-derived CO_2 emissions and 46 percent of South Africa's total.

At present, South Africa is a party to more than 40 international environmental treaties, including the United Nations Framework Convention on Climate Change, ratified in 1997. As a party to the convention, the country is required to report on national emissions and is encouraged to consider climate change issues in domestic social, economic, and environmental policymaking. South Africa also acceded as a party to the Kyoto Protocol in 2002. However, under both the convention and the protocol, South Africa is recognised as a "developing country" and has no commitments to reduce greenhouse gas emissions (mainly carbon dioxide, hydrofluorocarbons, and nitrous oxides).

The high carbon intensity of Eskom's generation raises issues for new investment, as sub-critical coal plant is considerably less efficient than newer super-critical plant. Eskom appears to be committed to super-critical coal-fired plant in future, perhaps as a result of employing a shadow price for carbon set at half the European ETS level. Certainly, the alternative of

[65] From Eskom's web site at http://www.eskom.co.za/enviroreport01/sust.htm

[66] Provided "the financial benefit associated with carbon savings under the CDM of the Kyoto Protocol is quantifiable with sufficient certainty to be included in the levelised cost calculation" (Eskom 2006 *Eskom's integrated and prioritised capacity expansion plan*)

investing in nuclear power to reduce carbon intensity would be unlikely to be cost effective without a significant carbon price (for example, those offered by the World Bank's Global Environment Facility or Clean Development Mechanisms). The costs of LNG-fired generation are so high as to be prohibitive. The most cost-effective way of reducing South Africa's CO_2 emissions would probably be to stop subsidising electricity.

Regulatory challenges

Given Eskom's dominant market position and the absence of competitive wholesale and retail electricity markets, it is understandable that the entire value chain, from generation to retail, is regulated. NERSA is governed by the National Energy Regulator Act which specifies its composition (four full-time and five part-time members, plus the secretariat), its functions, duties, funding, accounting, reporting, how meetings should be conducted and the processes for making decisions. The regulators' meetings are open to the public, and public hearings must be held on key regulatory issues and decisions may be appealed in the High Court.

The Electricity Regulation Act passed in 2006 makes clear all generation, transmission, distribution, trading and import/export activities need to be licensed by NERSA. The Electricity Regulation Amendment Act of 2007 inserts additional clauses on the regulation of "municipal reticulation" which it defines as meaning "trading or distribution of electricity and includes services associated therewith". Furthermore, it allows the minister to make regulations regarding "norms and standards for the setting of reticulation tariffs, in consultation with the Minister of Finance".

The new Act presents potentially serious contradictions. On the one hand it makes clear that municipal electricity distributors will have to be licensed by NERSA and these licences empower NERSA to set tariffs. However, it also gives the minister powers to establish norms and standards for setting reticulation tariffs and quality of supply. It is therefore not clear who ultimately regulates municipal electricity services. NERSA's regulatory discretion could be severely constrained.

The Electricity Regulation Amendment Act also has profound implications for restructuring of the sector as it now specifies for the first time that "electricity reticulation" means all distribution and retail functions. The Constitution gives municipalities executive and administrative authority of electricity reticulation. So, under these provisions, any restructuring process can only be with the consent of municipalities. Furthermore, Eskom or REDs or any other entities could only undertake electricity distribution activities if service delivery agreements have been entered into with municipalities. These provisions will also constrain retail competition and it is difficult to see how large customers could choose Eskom as their supplier without municipalities agreeing. The easiest way of resolving these contradictions would be to remove the phrase "electricity reticulation" from Schedule 4B of the Constitution.

A number of further regulatory challenges face NERSA, not least those of moving electricity prices towards LRMC and ensuring that peak prices reflect marginal costs of providing new peak power. As NERSA reported in September 2006: "The multi-year price determination set the first control from 1 April 2006 to 31 March 2009 and was done in a way that addressed government policy objectives of having the lowest prices consistent with Eskom being able to finance its business." It is difficult to reconcile this objective with its stated objective that prices should be efficient and cost-reflective. NERSA's economic regulatory methodology is set out in consultation papers for Eskom's next multi-year price determination. However, it is far from clear from these papers what are the precise methods or formulae they intend using for determining revenue requirements and which regulatory controls will actually be applied.

We have already alluded to the challenges NERSA faces with respect to timely and efficient licensing of new capacity. There is clearly a need to coordinate and integrate electricity planning, investment approval and licensing processes. NERSA will also have to establish more robust criteria for assessing the efficiency of capital expenditure.

Other areas of importance to NERSA in the next few years are standard PPAs and feed-in tariffs that will facilitate the entry of co-generation and renewable energy. NERSA will also want to ensure that investments in DSM and energy efficiency are accelerated. Finally, as the national electrification programme becomes more expensive, NERSA will need to track the efficacy and appropriateness of connection and consumption subsidies.

Policy and implementation challenges

The electricity supply industry is highly capital-intensive, has very durable assets, and delivers a service that is of crucial importance to consumers, whether domestic, commercial or industrial. The network is a natural monopoly, directly connecting consumers to the source of power, and the potential exploitative power of an unregulated monopolist is such that regulation is inevitable. The fundamental governance problem is that consumers want cheap power, while investors want secure future profits if they are to sink large sums in durable capital. Without secure title to a reasonable future profit flow, private investors will be loath to invest and state ownership will be the default option. The state has access to funds that can be invested, but finds it hard to resist calls for lower electricity prices.

Internationally, the classic conflict is between a finance ministry reluctant to pour money into a bottomless pit, sceptical that the engineers in charge are working to minimise costs, and other parts of a government wanting to preserve low electricity prices for electoral advantage. Their reluctance to raise prices hinders the ability either to fund investment and maintenance out of profits, or the creditworthiness to borrow against future profits. In extreme cases the electricity supply industry cannot even maintain existing equipment; reliability and availability drop, and power outages become the norm. India is a classic example of this unsatisfactory equilibrium.

Some countries avoid this dilemma. If the main politically powerful consumers are large, capital- and energy-intensive industries with long investment time horizons, they will demand (and be willing to pay for) adequate and secure electricity supply. With a politically weak and small consumer sector, pre-democracy South Africa fitted that description. Low-cost coal and cheap finance allowed electricity to be delivered at prices competitive for internationally trading energy-intensive industries.

The transition to democracy has changed the power balance and created potential new tensions between different consumer objectives. Eskom foresaw this and invested heavily in rural electrification, buying time from its accumulated and strong credit position. Falling real prices bought consumer support without compromising quality of service, at least while reserve margins remained lax and transmission lines were reasonably maintained. That honeymoon has ended before the electricity supply industry had been restructured to cope with these new tensions.

The dominant model for protecting the electricity industry against the erosion of investment and supply has been restructuring and privatisation of both transmission and distribution. Competition between generators and among retailers obviates the need for overregulation of those potentially competitive sectors, while the wires business can be assured of a stable funding environment through multi-year price controls, adequate cost pass-through mechanisms, and a robust dispute resolution process. This model is, however, demanding, requiring credible institutions to enforce contracts, resolve disputes, and supply the necessary high-calibre regulatory personnel at competitive salaries.

Competitive generation works best when investments can be delivered in short time periods at low capital cost and modest scale, and where there is a liquid, competitive wholesale market. It works well with gas-fired generation at the margin, in countries adequately interconnected to other large markets, and where fuel and electricity price risks can be hedged in liquid contract markets. The process of restructuring is inevitably time-consuming, will be resisted by the incumbent, and thus requires a period of spare capacity while management is concerned more with restructuring businesses than building new capacity.

On the face of it, South Africa satisfied many of the necessary preconditions for successful liberalisation. It had the necessary credible institutions to enforce contracts, a commercial culture, a strong financial sector and high-calibre regulatory personnel. Unlike the US, but like Britain and many European countries, it does not have a history of regulation upheld through a series of test court cases, but it does have a strong Constitution that defends property against arbitrary transfer. In the 1990s South Africa had spare capacity. What it lacked was enough time or commitment to this model to deliver it before margins became tight and the luxury of competitive tendering could be put in place.

Eskom would doubtless prefer to remain a national champion, but that is incompatible with creating enough competing generation companies to sustain a plausibly liquid wholesale market. Raising fears that the lights may go out can swiftly undermine any enthusiasm for dramatic restructuring options. The number of countries that have actively created an adequate, or even a larger, number of competitive generators at privatisation is miniscule. Britain broke up the CEGB into three generators, of which only two companies were initially sold. Spain merged companies before liberalising the market (and then had to heavily regulate it). France refuses to dismember EdF, while Germany, which had few federally owned companies, presided over a merger boom that concentrated generation into four main companies, and allowed mergers between the dominant gas and electricity companies.

It is not surprising that Eskom has survived the restructuring debate intact, and is now in a position to dominate the debate on delivering needed capacity. The good news is that Eskom's delivery will be under intense scrutiny, as prices will have to rise, and funds located to pay for the huge investment programme. Scrutiny will be crucial to guard against any imprudent borrowing or investment that could have an impact on the state's creditworthiness. Consumers will also take note of any decline in the quality of supply, delays or cost overruns – all of which are likely to occur. The bad news is that it will be hard to develop durable solutions to the growing tensions between efficient management, maintenance and investment, and the desire for cheap power.

In the short run, options are limited. The most pressing need is to place orders for new Eskom plant and ensure that prudent and timely decisions are taken about the independent power producers that are required to deliver the necessary capacity. Government needs to decide on its electricity pricing policy (and implicitly its industrial strategy), and specifically how quickly to raise prices to LRMC for each major segment of the market. Given a decision on pricing, it remains to determine how best Eskom's investment plan is to be financed, whether its equity is to be revalued, what dividend flow to require, and what residual borrowing is therefore required.

In the medium run, there are difficult decisions to make about whether to reduce South Africa's CO_2 emissions in the face of cheap coal, the high capital cost of new nuclear power and the very high cost of LNG. In the longer run there is the more fundamental question of the future desired structure of the electricity supply industry. The idea of separating distribution from generation and transmission appears to have been accepted and is clearly a desirable end-state. The policy of allowing independent power producers also appears to have been accepted, and has more important implications for restructuring Eskom to avoid conflicts of interest.

The natural transitional model here is of a transmission system operator and owner acting as the single buyer. This would hold Eskom's financial assets, planning capability, financing operations and most head-office functions, owning the non-generation equity assets (except in due course for distribution). Power stations would then hold PPAs with the single buyer. This model has a number of attractions, in that it should ensure fair dealing between IPPs and (former) Eskom generation stations, and may therefore encourage a more timely and lower-cost supply of private participants. There are some potential risks if it alters the balance of bargaining between coal-field owners and potential coal-fired generation companies, and it may delay the process of investment commitment. It may therefore be a longer-term objective.

In Europe the single-buyer model was rejected, and unbundling with competitive wholesale markets was proposed as the best model for liberalisation. However, this model is not suitable for South African circumstances.

Effective competition requires different owners, and that almost inevitably requires privatisation. Privatisation requires selling the generation assets. The value of these assets depends on the market price of electricity – in an oversupplied market competition can continue to deliver lower prices (near avoidable cost), but in tight markets prices rise to or above the entry price, or LRMC. The South African market is and will remain tight for many years.

In a tight market with long construction lags, competitive prices would rise far above LRMC unless generators held medium-term PPAs at below-market clearing prices. That would of course be possible, but it moves the model closer to the single-buyer model described above. The single-buyer model can be a transition to a genuinely competitive wholesale model, where the transition is to a period of adequate reserves, and retail prices finally set at LRMC – a scenario that Eskom does not envisage for several decades. As such it does not fall within the time frame of short- or medium-run decisions. That said, it provides an additional reason to start moving prices now towards LRMC with reasonable speed.

5. RECOMMENDATIONS

Electricity policy

Important elements of electricity sector policy as expressed in the Energy Policy White Paper of 1996 are out of date and contradict recent policy decisions made by Cabinet. Other elements, such as the emphasis on efficient and cost-reflective pricing, appear to have been downplayed or ignored. A new electricity sector policy should be developed and published that deals with sector goals, supply security, planning, private-sector participation, investment decision-making and approvals, procurement, co-generation and renewable energy, energy efficiency and demand-side management, environmental issues, electrification, distribution restructuring, pricing and regulation.

Electricity security, generation planning and investment

- A commission of inquiry should be established to determine the root causes of the current electricity shortages as well as the performance of Eskom's management in restoring electricity supply security. Based on the evidence before the commission, required management and operational changes should be implemented.

- An electricity security of supply standard should be established by the Minister of Minerals and Energy in consultation with the DPE, Eskom and NERSA. The security standard should be based on a reasonable measure of reliability such as loss-of-load expectation or loss-of-load probability and a related reserve margin. The system operator should be charged with the responsibility of reporting and publishing actual performance against this security standard. NERSA should be responsible for monitoring security of supply and recommending early remedial action when necessary.

- Electricity planning should be coordinated and integrated by transferring the National Energy Regulator's responsibility for planning (the National Integrated Resource Plan) to Eskom's new system operator and planning division (and drawing on the Integrated Strategic Electricity Plan) to create a new integrated planning function. This would help to eliminate confusion and contradiction. A suitable governance arrangement should be established that would allow adequate inputs by all key stakeholders – without compromising operational efficiency. National electricity plans and investment opportunities should be published on an annual basis.

- The processes whereby new generation capacity opportunities are allocated to either Eskom or the private sector should be transparent, clear and rational. Investment approval and licensing processes for new generation capacity should be streamlined through improved coordination between electricity planning, the allocation of new build to Eskom or the private sector, DPE approvals, DME agreements and NERSA licensing.

- Procurement of new private-generation capacity in the form of independent power producers with off-take agreements with Eskom should be made more efficient. The process should be conducted through a new single-buyer office, situated initially in Eskom. Independent oversight of this office's functions will be required by NERSA, DPE, DME and National Treasury to ensure that contracting terms for private producers are fair.

- The progress of Eskom's generating-capacity expansion programmes should be closely monitored by NERSA. The regulator and the DME should facilitate efforts to obtain economic (Eskom's avoided cost) off-take agreements for co-generation plant, renewable energy and for unsolicited energy supplies offered by independent power producers (up to an agreed maximum capacity) and should fast-track licensing approvals for such plant**.** Every effort should also be made to facilitate further demand-side management.

- The Department of Minerals and Energy, in consultation with NERSA and Eskom, should establish a prudent maximum electricity-import percentage. The single-buyer office, under the oversight of the National Energy Regulator, should ensure that imports and new projects in the region (both subject to maximum-allowed import levels) are not discriminated against in plans for expanding electricity generation.

- Once supply security has been established, consideration should be given to separating Eskom generation plant from the transmission and system operator, and associated planning and single-buyer functions. In other words, Eskom would become the single-buyer, and generation plant (ex Eskom and independent power producers) would be contracted on medium-term PPAs (leaving open the option of establishing a wholesale market at a future date).

Transmission

The business case requirements in the grid code for an "N-1" transmission reinforcement should be reviewed so that that the necessary investments are made to ensure adequate transmission infrastructure. The assumptions used in the business case models should also be reviewed – for example, the cost of unserved energy.

Distribution

- The highest priority should be given to ironing out policy uncertainties concerning the rationalisation of the electricity distribution industry. Institutional instability in the electricity distribution sector could threaten security of supply. A clear route-map needs to be provided as well as effective project management to implement the mergers.

- If the REDS model is selected, then the six distributors should be anchored in Eskom's six distribution regions to minimise institutional disruptions and to capitalise on Eskom's superior systems and project management capability.

- If problems in implementing the above model become insurmountable, an alternative plan should be considered in which the 12 largest municipalities (which represent 80 percent of municipal electricity sales) should be allowed to keep their electricity businesses and intensive support should be provided to strengthen their governance, management, accounting and investment in assets and people. Medium-sized municipal distributors that are performing well should also be allowed to continue operating. The Municipal Finance Management Act and the Municipal Systems Act should be amended to insulate these businesses from political interventions by municipal councillors and micro-management by municipal staff. Eskom would continue to be responsible mainly for rural customers and also large contestable customers (with consumption in excess of 100GWh/pa). Appropriate incentives should be provided for poorly performing medium and small municipal electricity distributors to be transferred either into Eskom or into larger municipal distributors.

Environmental issues

Given the low cost of coal compared to environmentally less-damaging generation options, such as nuclear, liquefied natural gas (LNG) and renewables, and given the capital-intensive characteristics of nuclear power, any decision to diversify away from coal should be considered very carefully, based on a realistic and preferably contracted long-term price of carbon. It is understood that Eskom now applies a shadow value to carbon. This does not, however, feed through to cash flow, and fails to create properly costed disincentives to carbon-intensive energy solutions. Government has a clear duty to consider the matter carefully.

Pricing and regulation

- Government should formulate a policy that empowers the regulator to award the kind of revenue levels to Eskom that would foster a migration of prices to long-run marginal costs and tariffs that reflect scarcity prices at the margin. Average base-load prices would need to move towards at least the LRMC in relation to generation, even if transmission and distribution were priced at average cost. Peak-load prices should reflect the very high cost of generation and marginal transmission losses (twice the average), as well as long-run marginal capacity costs. Off-peak prices would exclude capacity costs.

- NERSA should allow the required revenue that would encourage Eskom to pursue cost-effective demand-side management programmes, supported by tariffs that reflect scarcity prices.

- Eskom should not offer new long-term contracts to large users at less than the LRMC, and should not accept new large supply commitments that prejudice security of supply. In effect this may mean that new contracts can be interrupted.

- Average revenue per kWh for existing customers can evolve more gradually towards the LRMC. Price increases over the period to 2012, combined perhaps with a revaluation of Eskom's assets, would ease the debt-equity constraint somewhat, although other vital financial indicators would also need to be tracked.

- NERSA should encourage Eskom to move towards greater regional differentiation of energy prices (perhaps offset by a change in fixed charges for domestic customers in some areas).

- The Electricity Regulation Act should be amended to make retail choice possible for large customers.

- The Municipal Finance Management Act requires Eskom to consult municipalities on proposed tariff changes while also seeking regulator approval. There is also some ambiguity in the National Electricity Regulation Amendment Bill regarding the powers of the National Electricity Regulator to licence electricity reticulation and to set municipal tariffs. The regulatory process should be streamlined by eliminating parallel approval processes and clarifying the regulator's tariff-setting powers over municipal electricity reticulation.

Electrification

Data used for electrification planning probably overstates the numbers of households with access to electricity. The costs of new rural connections are increasing rapidly. There is little chance of universal access being achieved by 2012 at current connection rates. A new, more realistic policy should be developed that maps out the costs and benefits of expanding access and assigns pragmatic targets with required funding and clear accountability.

Appendix 1: Legislation governing the electricity sector

South Africa's electricity sector is governed by the following legislation:

- The Constitution of South Africa (1996), which grants municipalities executive authority and the right to administer "electricity reticulation"
- The Eskom Conversion Act (2001), which clarifies Eskom's status as a public company subject to the Companies Act (with certain exemptions) with 100 percent of its equity held by the state, governed by a shareholder compact and liable for payment of dividends and taxes
- The National Energy Regulation Act (2004), which defines the composition, powers and functions of the National Electricity Regulator
- The Electricity Regulation Act (2006), which defines the electricity regulatory functions of the National Electricity Regulator; an amendment to the act deals with the regulation of electricity "reticulation" as defined in the Constitution
- The National Nuclear Regulator Act (1999), which regulates nuclear safety issues
- The Public Finance Management Act (1999), which provides the framework for Eskom's reporting and accounting responsibilities to government as a public enterprise
- The Municipal Finance Management Act (2003), which defines how municipal entities such as municipal electricity utilities should be managed
- The Local Government Municipal Systems Act (2000), which includes sections on municipal administration of electricity reticulation and tariffs
- The National Environmental Management Act (1998)
- The Air Quality Act (2004).

Appendix 2: Estimating the value of Eskom's assets

Value of generation assets

A very rough check of the valuations provided by Eskom can be arrived at by estimating the optimal deprival value (ODV) of the generation assets (actually just the coal-fired and nuclear station) as follows.[67] Each station's annual cash flow can be projected by taking an estimate of the LRMC of generation as R250/MWh (reflecting the estimates in ISEP10), and factoring in an estimate of the variable generation costs of each station deduced from the station-specific fuel, fixed and variable costs from NIRP2, and the low estimate of energy sent out from each station taken from the ISEP10 plans. Fuel costs were assumed to rise by 20 percent in 2007 compared to the ISEP10 values, and thereafter continue to rise at 2 percent a year until 2025, after which they stabilise. The resulting gross profits are then discounted over the period from 2007 until their estimated scrapping date at 10 percent real to 2007 – this gives the ODV as the net present value of R239 billion.[68] Eskom considers this value to be on the high side, perhaps because operations and maintenance costs have been under-estimated, and/or perhaps because availability has been overstated.[69] This report takes a very rough value for the ODV of R200 billion. The carrying value (i.e. the written down book-value at historic cost) of generation assets in March 2006 was R26.4 billion. Eskom's current cost accounts (CCA) show generation assets at R70 billion in 2003, but at original cost-inflated but not depreciated the assets would be valued at R187 billion. If the values are updated to March 2006 values using the consumer price index, they appear as shown in the first two columns of Figure 40. Note that the 2007 *Forward Price Curve* has increased this estimate to R270/MWh for generation as coal costs have risen more than predicted when this estimate was made.

[67] The ODV of assets, or their value to the business, would be the lower of the replacement cost of the assets that are worth replacing and the recoverable amount – the present value of the future cash flows obtainable and cash flows obviated as a result of the asset's continued use and ultimate disposal net of any expenses that would need to be incurred.

[68] The output is computed by taking the ratio of the available capacity to the maximum capacity, and multiplying by the low value of the maximum energy sent out per year from Table 10-1 of ISEP10.

[69] It is important to realise, though, that the ODV is based not on the likely sales revenues from selling at prices approved by NERSA, but the sales revenue assuming that from now on all electricity is sold at the LRMC, which is likely considerably higher.

Figure 40: Estimates of Eskom's asset values in 2006 rands (R billion)

	CCA original cost 2003 at 2006 prices	CCA current value 2003 at 2006 prices	HC carrying value 2006 March	HCA depreciation	Estimated ODV	Depreciation on CCA cost	ODV/ CCA	ODV/ HC
Generation	197.6	76.5	26.4	2.2	**200**	4.9	***2.6***	7.6
Transmission	49.0	12.5	7.2	0.5	33	1.2	2.6	4.6
Distribution	78.1	31.4	19.7	1.5	80	2.0	2.5	4.1
Land and buildings	21.5	6.6	1.8	0.0	17	0.4	2.6	9.4
Other	8.4	1.9	1.9	0.4	5	0.6	2.6	2.6
Total in commission	354.6	128.9	57.0	4.6	335	9.1	2.6	5.9
Mothballed plant	15.6	3.9	0.0					
Work under construction	3.6	3.6	6.5					

Source: Eskom's accounts (2003, 2006) and calculations

Even when zero value is attributed to all peaking, hydro, pumped storage and import contracts, the ratio of the book value to the estimated ODV is 13 percent, while the ratio of the written down CCA 2006 value to the estimated ODV would be about 35 percent. The ratio of the original cost at current prices to the estimated ODV would be 82 percent, consistent with over-rapid depreciation even by the standards of CCA value. The estimated ODV might thus be 2.6 times the CCA written-down 2006 value, and 7.6 times book-value at historic cost.

Estimated value of all assets

As this seems a defensible and conservative estimate it can be used to estimate the ODV of the remaining assets, by the simple expedient of multiplying all CCA values by the same factor of 2.6 (with the exception of distribution, where its original cost at current values is chosen), as shown in Figure 40. That gives an ODV valuation of Eskom's assets in commission in 2006 (and at 2006 prices) of about R335 billion. On that basis, the ratio of pre-tax profit to ODV is 7.6/335 = 2.3 percent. Of course, as the previous corrections from historic-cost to inflation-adjusted profits suggests, the net profit would also need adjustment, and this might be significantly downward. Thus in the inflation-adjusted accounts, Eskom reports "real (inflation adjusted) return on total assets" for the four accounting periods from 2000 to 2003 as 2.45 percent, 1.17 percent, 1.69 percent and 0.53 percent.

If we try to identify the returns to these physical assets, we find that the company's "value created" (i.e. revenue less raw materials and consumables) was R22.6 billion, wages were R7.3 billion, depreciation was R4.6 billion, so profits before interest and tax were R10.7 billion. Depreciation is clearly overstated in one sense – it writes all assets to zero over a period shorter than the economic lifetime – but may be understated in that the asset valuation is well below ODV. The simplest rough approximation would be to take the original cost up-valued to 2006 prices, and take asset lives of 40 years for generation, 40 years for transmission and buildings,[70] 40 years for distribution and 15 years for other (mainly vehicles and equipment) to give the amounts shown in sixth column of Figure 40. That suggests a more accurate estimate of depreciation of R9.1 billion. The economic return is thus R22.6

[70] Eskom argues that a more realistic life for transmission would be 30 years.

billion - R7.3 billion - R9.1 billion = R6.2 billion; and the ratio of return to physical asset value might be 6.2/335 = 1.8 percent.

This return can be compared with the weighted average cost of capital (WACC) from ISEP10 of 7.6 percent real (and a current allowed rate by the national regulator of 6.5 percent),[71] which itself may be somewhat on the low side. For convenience the WACC is taken as 8 percent real for calculating interest costs.

Value of transmission assets

Transmission accounts for just over 8 percent of the regulated revenue of the whole electricity supply industry. Figure 40 shows the book value of these assets is R7.2 billion (historic cost of R12 billion minus depreciation of R4.8 billion), the current CCA value as R12.5 billion, and original cost at current prices as R49 billion, suggesting that they have been written down very heavily. The National Electricity Regulator (2004) shows transmission revenue as R3.8 billion in 2004 and expenditure as R1.6 billion, made up of R0.5 billion for labour, R0.4 billion for general costs, R0.3 billion for corporate overheads, R0.4 billion for depreciation, and only R34 million in interest (down from R370 million in 2000). If the ODV is 7.6 times the book value, then the transmission assets would be valued at R55 billion. If it is 2.6 times the CCA amount its value would be R32.5 billion, close to the figure estimated in Figure 40.

Eskom has 27 169km of high-tension grid including 132kV line; it has 26 225km of line above 132kV. In comparison, Britain's National Grid Company has 17 391 km above 132kV and a regulatory asset value at January 2007 of £5 billion (R71 billion at 2007 exchange rates). As the National Grid Company first regulatory asset value was based on a sales value that was considerably below its written-down modern-equivalent asset value (effectively the ODV if the entire network is useful), that suggests that Eskom's longer (but sparser) network is substantially undervalued in the accounts. If we take the cost of new transmission grids at R3.3/m/km the replacement cost of just the grid would be nearly R90 billion (with the written-down value substantially below this), confirming the suggestion that the book value of R7.2 billion is a substantial underestimate, but also indicating that R55 billion might be an overestimate. Figure 40 settles on an ODV value of R33 billion as a compromise.

Depreciation is shown as R0.5 billion in the accounts. Depreciation should measure the amount that is needed to maintain the network based on replacement values. Therefore basing it on replacement cost rather than book values would likely produce a better estimate of the correct amount to be retained for maintenance and replacements, hence the value in Figure 40 of R1.2 billion. Finally, the WACC on the book value would be 8 percent of R7.2 billion = R0.6 billion, while on an ODV of R33 billion it would be R2.6 billion. Whether or not to charge the WACC on a notional value (such as the book value) or the ODV is less of an issue than that of designing an appropriate structure of grid charges. When labour and other costs are added to the revised interest and depreciation, the total ranges from R2.7 billion to R5 billion, depending on whether to value the assets at book value or ODV. The lower figure is nearly twice 2004 expenditure but less than 2004 revenue of R3.7 billion. Revenue increased 61 percent from 2003, presumably as Eskom reallocated costs properly ascribed to

[71] The pre-tax WACC for the first period is 7.3 percent but that approved for the current period is 6.46 percent (NERSA First Consultation Paper, Sep 2006, p30). However, according to Eskom's memo of 25 April 2005, "the NERSA methodology awards Eskom the 'real' rate as a nominal rate (i.e. applied as is in each year, without scaling up with inflation), it is only 'real' in the sense that the asset values are indexed to the rate of inflation. That makes a significant difference to the revenues/cash flows".

transmission. Current average grid charges are therefore defensible, although one could also defend a higher amount.

Value of distribution assets

Distribution accounts for 25 percent of regulated revenue within the electricity supply industry. Eskom's distribution assets have been written down from a cost of R32.4 billion to a carrying value of R19.7 billion, of which R5.8 billion is attributable to electrification. The CCA (2006) value is R31.4 billion, and the assets' original cost at current prices was R78 billion, suggesting that they have been written down very heavily. A breakdown of costs was not readily available for Eskom, but the National Electricity Regulator (2004) gives a breakdown for the whole sector. Eskom accounts for 58 percent of the total sales revenue, 55 percent of energy delivered, but only 46 percent of net end-user revenue. If we assume that Eskom accounts for half the total costs, then its non-electricity costs were R11.1 billion, of which capital costs were R2.3 billion in 2004.

Grossing up book-valued distribution assets, ODV would come to R150 billion for 300 000km of distribution lines (7.6 times historic cost) or a value of R82 billion (2.6 times CCA value), about the same as the original cost at present prices. For comparison, the 2006 regulatory asset value of the British distribution assets was £13.5 billion (R192 billion) for a network of 244 000km (although one built to a considerably higher standard and involving relatively more expensive urban underground lines). As with the grid, however, the British distribution companies were valued post-privatisation at their sales value, not the ODV value. It would seem that a substantially higher regulatory asset value than R20 billion could be justified for Eskom's distribution division, with a preferred estimate of R80 billion, slightly above the original cost at current prices.

If distribution assets have an economic life of 40 years (the same as transmission) then based on original cost at current prices depreciation might be R2 billion. The WACC at 8 percent on the book value of R19.7 billion would be R1.6 billion (but on ODV might be R4.8 billion), so an estimate of total capital charges might be between R3.6 billion and R6.8 billion, compared with capital costs plus profit of R3.5 billion. This suggests an under-recovery of between roughly zero (book value) and R3.3 billion (ODV), all on a net end-user sales revenue of R20.9 billion. Therefore, distribution costs should rise by anything between zero and 16 percent.