INTEGRATED RESOURCE PLAN FOR ELECTRICITY

2009

REPORT

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SUMMARY

Electricity demand is expected to grow at an average 3,5% over the next five years alongside a recovery in global and national economic performance. There is some uncertainty regarding the timing of the turn around and the extent to which local industry will rebound over the period which is reflected in a cone around the expected energy demand.

The impact of electricity price increases are included in this forecast, allowing for an increase in efficiency as high medium-term increases impact on industrial and other consumption patterns. Demand-side management programmes are also expected to reduce the overall demand growth marginally over this period.

The demand growth is expected to taper off to a longer term average of 3,2% over the 20-year planning horizon. The spurt from the recovery is expected to dissipate after 2014, while efficiency improvements and a general switch from energy-intensive industries over time allows economic growth to continue with reduced electricity demand growth.

For the purposes of the IRP Eskom is expected to continue with the current build programme of Medupi coal-fired power station (first unit commissioned in 2012), Kusile coal-fired station (first unit commissioned in 2013), Ingula pumped-storage station (commissioned in 2013) and the finalisation of the return-to-service programme (RTS) of the previously moth-balled coal-fired power stations. In addition the Renewable Feed-in Tariff programme (REFIT), Medium Term Power Purchase Programme (MTPPP) and the open-cycle gas turbine (OCGT) independent power producer (IPP) are expected to provide additional capacity in the medium term.

From the demand side perspective the IRP incorporates known demand side management programmes with expectations of the success of these. Included in these programmes are commercial, industrial and residential programmes totalling a cumulative saving of more than 15TWh by 2019.

Due to the inherent uncertainty in the demand forecast as well as uncertainties around expectations of power generator performance a certain amount of reserves is required to avoid supply interruptions. Building additional generation capacity to provide these reserves adds additional cost to the system which needs to be weighed up against the economic cost of supply interruptions. The IRP will cater for this by incorporating a cost of unserved energy to internalise this trade-off in the optimisation of the expansion plan. However should policy dictate a higher reserve margin this would come at additional cost in the expansion programme.

The least-cost reference expansion plan would provide for the construction of coal-fired power stations to meet the demand over the planning horizon, with OCGT power stations providing peaking energy. This outcome is not surprising given the relative low direct cost of coal-fired power stations and relatively high

domestic reserves of coal to meet future demand. The detail for the least cost expansion plan is indicated in Appendix C.

While the reference plan indicates the least-cost alternative these costs do not include the inherent externalities involved in coal-fired electricity production, in particular growing concerns regarding greenhouse gas emissions as well as a security of supply imperative in diversifying the national energy base.

In the absence of a specific government target on greenhouse gas emissions the Long Term Mitigation Strategy was used to provide firstly, a firm target of emissions in 2025, and secondly, an alternate of a carbon tax as a mechanism to achieve this target. Scenarios were developed around these inputs, allowing for some regional shift in emissions and a potential delay in the implementation of the emission ceiling until 2025.

A number of scenarios were generated to cater for the emission constraints as well as the policy objective of increased private participation in the electricity generation sector. These risk-adjusted scenarios were assessed based on criteria of cost, emissions and diversity objectives, as well as discounting for additional risk to the system.

Additional policy adjustments were included in the proposed IRP after discussions with the Department of Energy. These included allowance for additional DSM projects (such as the million solar water geysers target), a nuclear fleet strategy and the inclusion of hydro capacity from the region.

The final policy-adjusted IRP is presented in the table below as the IRP that best meets the criteria of cost, emissions, diversity and risk, and the policy requirements of the Department of Energy.

A number of critical assumptions were included in the development of the risk-adjusted IRP. These include:

- The development and commercialisation of renewable energy alternatives, in particular Concentrated Solar Power (CSP), which – at assumed cost calculations – would offer an effective mid-merit power source with reduced emissions;
- The development of a nuclear strategy to provide low emission base-load alternatives to coal-fired generation from 2020;
- Continued investment in the maintenance and refurbishment of existing Eskom (and non-Eskom) plant to ensure generator performance at assumed levels;
- Continued investment in demand side management initiatives to improve energy efficiency and delay additional capacity requirements. This includes the expected load reduction stemming from the Department of Energy’s one million solar water geyser target.

The plans do not fully address concerns regarding long-term water usage for power generation. Although nuclear power stations placed along the coasts reduce the fresh-water requirement, other sources such as CSP and coal-fired generation are intensive water users. While regional imbalances can be alleviated through water infrastructure development the long term impact on overall water balances in the country is still to be addressed. In addition constraints relating to sorbent availability and disposal, transmission infrastructure and financial constraints relating to capital investment are not fully incorporated in the modelling.

	Committed	Coal 3	Coal 4	Coal 5	Nuclear fleet	CCGT	CSP (Generic)	Import hydro	Kudu	Moamba	OCGT	Total new build	Total system capacity	Total DSM (incl DoE SWH project)	Peak demand (net sent-out) forecast (after DSM)	Reserve Margin
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
2009	772	0	0	0	0	0	0	0	0	0	0	772	44157	432	37413	18.03
2010	1156	0	0	0	0	0	0	0	0	0	0	1156	45313	923	38509	17.67
2011	1997	0	0	0	0	0	0	0	0	0	0	1997	47310	1343	39571	19.56
2012	1022	0	0	0	0	0	0	0	0	664	0	1022	48996	2118	40255	21.56
2013	2127	0	0	0	0	0	0	0	0	0	0	2127	51123	3056	41182	23.98
2014	2865	0	0	0	0	0	0	0	0	0	0	2865	53988	3935	42576	26.65
2015	2024	0	0	0	0	0	0	0	0	0	0	2024	56012	4225	44939	24.50
2016	1381	0	0	0	0	0	0	0	0	0	0	1381	57393	4525	46744	22.64
2017	723	714	0	0	0	0	0	0	0	0	0	1437	58830	4825	48586	21.03
2018	0	714	0	0	0	0	0	0	0	0	0	714	59544	5125	50134	18.79
2019	0	714	0	0	0	0	0	0	0	0	294	1008	60552	5425	51840	16.90
2020	0	714	0	0	1650	0	0	0	0	0	0	2364	62916	5425	53720	17.00
2021	-75	714	0	0	1650	0	184	0	0	0	0	2473	65389	5425	55362	17.91
2022	0	714	0	0	0	0	368	0	0	0	0	1082	66471	5425	57093	16.52
2023	-909	0	0	0	1650	786	552	0	0	0	294	2373	68844	5425	58921	16.97
2024	-1424	0	0	0	1650	786	552	500	0	0	294	2358	71220	5425	60728	16.99
2025	-2740	0	0	0	1650	786	552	500	2358	0	0	3770	74344	5425	62666	18.01
2026	-2280	0	1428	0	1650	0	552	500	0	0	147	1997	76359	5425	64517	17.53
2027	0	0	714	714	1650	0	1104	0	0	0	0	4182	80541	5425	66391	20.23
2028	-2850	0	714	714	0	0	1104	0	0	0	0	-318	80223	5425	68007	16.86

1. INTRODUCTION

1.1. Purpose of this document

The Integrated Resource Plan (IRP) is a long term electricity capacity plan which defines the need for new generation and transmission capacity for the country.

This document outlines the concepts and development behind the integrated resource plan for the electricity industry in South Africa as well as the strategic objectives of the IRP including the policy and technical parameters that drive the planning process. Discussion is introduced on the methodology adopted to attain the appropriate plan along with information required to promote debate on the principles and results of the IRP.

1.2. Organisation of this document

The main portion of the document tackles the approaches and assumptions used for the IRP as well as the scenarios arising from the policy prescriptions. The document concludes with a recommendation for an IRP after consideration of the scenarios and criteria for "goodness-of-fit". Detailed discussion on the supply-side capacity options is provided in Appendix A, with the load forecasting model and process discussed in Appendix B. The criteria used for selecting the desired expansion plan are discussed in Appendix C.

1.3. Request for stakeholder comment

The System Operator invites feedback from customers, producers and other industry stakeholders regarding the methodologies, assumptions and results as discussed in the document.

2. PLANNING OBJECTIVES AND SCOPE OF WORK

The Energy Act of 2008 obligates the Minister of Energy to develop and publish an integrated resource plan for energy. As electricity forms a sub-component of the energy sector this electricity IRP needs to be integrated into the outlook for energy. The System Operations and Planning Division in Eskom has been mandated by the Department of Energy (DoE), under the New Generation Capacity regulations[1], to produce the integrated resource plan for electricity in consultation with the Department and the National Energy Regulator of South Africa (NERSA).

The objective of the IRP is to develop a sustainable electricity investment strategy for generation capacity and transmission infrastructure for South Africa over the next twenty five years. The investment strategy includes implications arising from demand-side management (DSM) and pricing, and including capacity provided by all generators (Eskom and independent producers).

The IRP is intended to:

- Improve the long term reliability of electricity supply through meeting adequacy criteria over and above keeping pace with economic growth and development
- Ascertain South Africa's capacity investment needs for the medium term business planning environment;
- Consider environmental and other externality impacts and the effect of renewable energy technologies.
- Provide the framework for Ministerial determination of new generation capacity (inclusive of the required feasibility studies) as envisaged in the New Generation Capacity regulations.

2.1. Governance

The Eskom ISEP Steering Committee provides overall direction for the planning process.

In the absence of an external state-driven governance process for the development of the IRP, the IRP was developed predominantly by Eskom structures with consultation with NERSA and relevant government departments. The internal Eskom structure has been centred on the recently re-instituted governance structures facilitating the long term planning process, specifically the Integrated Strategic Electricity Plan (ISEP). These structures are headed by the ISEP Steering Committee which provides the overall direction for the planning process as well as controlling the data and processes required for planning. A number of working groups have been instituted under the Steering Committee to focus on particular aspects of the ISEP process. These working groups support the implementation of the ISEP process as well as utilizing its outputs. In particular they collate the input data and finalize specific assumptions required.

The working groups are:

- The Load Forecast Working Group (LFWG)
- The Supply Side and Primary Energy Working Group (SSPEWG)

[1] Electricity Regulations on New Generation Capacity, 5 August 2009, Department of Energy

- The Demand Side Working Group (DSWG)
- The Sustainability Working Group (SWG)
- The Integration Working Group (IWG)

In the development of the IRP discussions with various stakeholders have been held.

Government departments involved in discussions on the IRP

Government departments, in particular the DoE and Department of Public Enterprises (DPE), have been involved in periodic discussions on the IRP and providing inputs to the assumptions and scope. In addition the NERSA has been consulted on the IRP development. The national electricity demand forecast (in particular the original ISEP forecasts) have been discussed with various industry bodies, including the Energy Intensive User Group (EIUG) and the Association of Municipal Electricity Undertakings (AMEU).

It is expected that in the near future an industry body will be constituted that will provide the necessary inputs and oversight for the IRP process.

2.2. Scope

As the plan addresses the supply and demand balance for the entire South African electricity industry (including foreign contracted sales and purchases) consideration is taken of non-Eskom sources of generation capacity and production.

The IRP will span the 20-year period from 2009 to 2028.

The IRP will span the 20-year period from 2009 to 2028, providing an indication of the long term requirements for electricity generation capacity incorporating the key period at the start of the decommissioning of some of the existing Eskom plant as well as the implementation of the potential emissions target regime.

A reference plan (or base plan) is produced as an optimal plan considering only the direct costs of all capacity options. Thereafter specific policy objectives and risk mitigation consideration are included in the planning to determine a risk-adjusted plan.

The policy environment forms a significant part of the foundation on which the study is based. Three particular elements are highlighted here:

- Emission policy
  South Africa may be subject to international climate change obligations in the near future which would encourage shifts from high-emitting fossil fuels to renewable or alternative energy sources. In terms of the IRP this emphasizes the need to internalise specific externalities such as the environmental impact of fossil fuels.

- Diversity

  The Energy White Paper of 1998 indicated a preference for decreased reliance on coal as the primary fuel source for electricity. It is expected that government policy, as well as Eskom directives, would promote greater diversity to include additional nuclear, natural gas or renewable options.

- Least cost

  The IRP is developed on the basis that the country builds capacity to meet expected growth at minimum economic cost (inclusive of externality impacts). The internalisation of the externalities is a critical issue in ascertaining the true cost of capacity expansion and evaluating alternatives. An alternative to building to meet expected growth at minimum cost is for the country to build in order to attract growth (i.e. look to provide excess capacity in order to ensure sufficient reserves to cater for new projects). The cost difference between the two approaches is not significant as the additional cost of excess capacity is not steep, however it does change the focus of the study, and was not the approach taken in the current IRP.

Site locations are of particular concern in Transmission planning studies. However long-term IRP plans are not currently sufficiently definitive due to substantive uncertainties remaining regarding final plant selection during the 25 year horizon. As such Transmission plans will incorporate scenarios involving "Inland" and "Coastal" plant locations. However limited integration costs for Transmission infrastructure is included in the generation capacity costs to appropriately gauge the cost differences between technology options.

2.3. Planning parameters

Adequacy criteria

Setting the adequacy criteria for generation capacity is a critical component of security of supply relevant to generation expansion planning. This parameter indicates the level of capacity that provides long term security to meet demand with allowance for contingencies.

The adequacy criteria is intended to indicate the level of additional capacity required to provide additional security of supply in the event of uncertainties, especially long term uncertainty regarding the load forecast and the assumed future performance of generating plant (as two examples). An unexpected spurt in economic growth (coupled with a degradation of generator performance) could have significant impact on the security of supply before the industry has an opportunity to build additional capacity to meet these eventualities.

Various adequacy criteria have been proposed for the IRP, including:

- A Capacity measure of 15% capacity reserve margin; or

- An expected un-served energy measure of less than 0,002% of the total expected energy in each year (or less than 20GWh in absolute terms).

On the other hand it is possible to allow the optimisation inherent in the model to determine the appropriate generation adequacy for the system based on the cost of un-served energy. This is a parameter provided to the model to determine the impact on consumers (and the economy) of an inability to meet the forecast demand in a specific period. If this is correctly modelled (with an appropriate value for the cost of un-served energy) the optimal expansion plan would incorporate the negative impacts of not meeting load. This should suffice to negate the need for explicit adequacy criteria, along with appropriate sensitivity studies to accommodate uncertainties in the underlying assumptions.

The cost of un-served energy is assumed to be R75000/MWh

For the purposes of the IRP the cost of un-served energy is assumed to be R75000/MWh.

The reserve margin is an outcome based on risks associated with uncertainties

If appropriate sensitivity studies are undertaken to ensure that a particular plan is sufficiently robust to deal with the long term uncertainties then whatever additional capacity is built in the plan should be sufficient to meet security of supply requirements. Thus the reserve margin will be an outcome based on the evaluation of risk associated with the key uncertainties identified.

It is expected that NERSA will provide guidelines or direction on the required adequacy for generation capacity and that future IRP will meet this requirement.

From the perspective of transmission or grid expansion planning the reliability standard is set for “n-1” or “n-2” contingencies. In order to properly integrate generation and transmission expansion plans the studies need to ensure that the requirements of the South African Grid Code are maintained as a minimum.

Discount rate

The real discount rate is based on the pre-tax WACC of 10,3%

The discount rate is based on the calculations of Eskom’s weighted average cost of capital (WACC) determined by Eskom Corporate Finance. This follows the generally accepted methodology of determining the required returns to overcome risks associated with corporate debt and equity. Table 1 below indicates the assumptions underlying the WACC calculation.

Table 1 – Parameters for Discount rate calculation

		2008 Real
Risk free rate	**Rf**	**2.5%**
Country risk		**1.5%**
Debt premium	**Dp**	**3.3%**
Gearing	**g**	**60%**
Equity Beta	**B**	**1.1**
Equity Risk Premium	**ERP**	**6.0%**
Tax rate	**T**	**28.0%**
Inflation	**I**	**7.0%**
Cost of debt	Kd	7.3%
Cost of Equity	Ke	10.6%
WACC (no-tax)		8.6%
WACC (post-tax)		7.39%
WACC (pre-tax)		**10.3%**

Source: Eskom Corporate Finance

The discount rate is an important factor in determining an optimal expansion plan due to the manner in which costs are reflected in the modelling. Capital-intensive projects would be penalised under a high discount rate (relative to less capital-intensive projects) as the capital costs are incurred upfront and operating and fuel costs incurred during the life-time of the projects. Heavy discounting of these future costs relative to the capital would result in the model favouring low capital projects with higher operating and fuel costs.

Other financial assumptions

There is an assumption in the modelling that the plans are affordable in that the model has not been constrained by affordability considerations. Implicit in this is that price increases over the next few years will bring the electricity industry in general (and Eskom in particular) into "balance", i.e. financially viable given the capacity requirement. If this were to be the case the reference (or least direct cost) plan provides a suitable benchmark for the costs of the alternatives. Thus the normalised increase in costs (relative to the reference plan) is important in determining the increased costs required in excess of the reference plan.

Technical assumptions

Appendix A covers the technical and financial assumptions for existing generators and potential supply-side options.

Appendix B covers assumptions for demand and demand-side interventions.

2.4. Modelling

Each of the scenarios determined below (including the reference case) has been modelled with the objective of minimising the direct costs of the expansion plan (including capital, fuel and operating costs). While certain constraints have been imposed, including emissions constraints in specific scenarios, these are always constraints on the cost optimisation objective. For the carbon tax scenario the shadow price of emissions was set equal to the carbon tax and entered as an input to the optimisation.

For modelling efficiency purposes the calendar year was converted into a load duration curve with time slices representing periods of similar demand. This mechanism has been used for the expansion plan optimisation. For the robustness check in the sensitivity analysis a full production optimisation has been executed on the chronological calendar year ensuring that the pumping cycle, amongst other considerations, is accurately reflected.

Planned outage co-ordination is modelled by allowing the system to optimise planned outages according to capacity availability. In addition unplanned outages are modelled by adjusting the load duration curve to an effective load duration which incorporates the probability of plant failure.

3. REFERENCE CASE

The least direct cost plan (or reference plan) is determined based on the cost assumptions for potential supply-side projects, assumptions for demand-side interventions as well as the underlying expected demand. All known, feasible projects are included in the reference plan.

Table 2 and Table 3 show the existing generation capacity and committed capacity respectively used for the purposes of the studies. The committed capacity includes the known Eskom projects for new generation and potential non-Eskom projects (particularly independent power producer programmes).

Table 2 – South African generation capacity assumed for IRP

	Capacity (MW)
Eskom	**40125**
Camden	1424
Grootvlei	190
Komati	0
Arnot	2220
Hendrina	1900
Kriel	2850
Duvha	3450
Matla	3450
Kendal	3840
Lethabo	3558
Matimba	3690
Tutuka	3510
Majuba	3843
Koeberg	1800
Gariep	360
VanderKloof	240
Drakensberg	1000
Palmiet	400
Acacia and Port Rex	342
Ankerlig and Gourikwa	2058
Non-Eskom	**3260**
Cahora Bassa	1500
Non-Eskom Coal	1080
Steenbras	180
Non-Eskom Other	500
TOTAL	**43385**

Committed projects

The Return to Service (RTS) stations (Grootvlei and Komati) will continue to re-commission generating units until 2011 as indicated in Table 3. Camden (also a Return to Service power station) has completed its re-commissioning programme.

Eskom is adding 60MW additional capacity at Arnot power station over the next two years (in addition to the new capacity already brought on-line and included in the Arnot capacity in Table 2 above). It is also expected that an additional 25MW will be provided by Cahorra Bassa

Table 3 – Committed new capacity and expected decommissioning

	Grootvlei (RTS)	Komati (RTS)	Additional energy from existing Eskom	Additional energy from existing non-Eskom	Medupi	Kusile	DoE OCGT IPP	Ingula	MTPPP 1	REFIT Wind	REFIT Other	Sere	Decommissioning	Net new capacity
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2009	570	202	0	0	0	0	0	0	0	0	0	0	0	772
2010	380	303	30	0	0	0	0	0	168	0	175	100	0	1156
2011	0	404	30	25	0	0	1020	0	168	200	150	0	0	1997
2012	0	0	0	0	738	0	0	0	84	200	0	0	0	1022
2013	0	0	0	0	738	723	0	666	0	0	0	0	0	2127
2014	0	0	0	0	1476	723	0	666	0	0	0	0	0	2865
2015	0	0	0	0	738	1446	0	0	0	0	0	0	-160	2024
2016	0	0	0	0	738	723	0	0	0	0	0	0	-80	1381
2017	0	0	0	0	0	723	0	0	0	0	0	0	0	723
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	-75	-75
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	-909	-909
2024	0	0	0	0	0	0	0	0	0	0	0	0	-1424	-1424
2025	0	0	0	0	0	0	0	0	0	0	0	0	-2740	-2740
2026	0	0	0	0	0	0	0	0	0	0	0	0	-2280	-2280
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	-2850	-2850

Two coal-fired power stations are under construction with Medupi's first unit expected to be operational in 2012, with the last unit operational during 2016, and Kusile, with the first unit operational during 2013, and the last by winter 2017. In addition the Ingula pumped storage station is expected to start operating in 2013.

Eskom is also expecting to build 100MW of wind capacity under the Sere project which should be operational during 2010.

IPP programmes

There are a number of independent power producer (IPP) programmes currently underway. The first of these, the medium term power purchase programme (MTPPP), is run by Eskom and allows for contracts for private electricity generation within certain price parameters for the medium term (i.e. 10 year window). It is expected that 417MW capacity will be developed under this programme, the first portion of which should become operational during 2010.

In addition the DoE has been running a tender process for the development of additional open cycle gas turbine (OCGT) capacity from private suppliers. This 1020MW capacity is expected by winter 2011.

The Renewable Energy Feed-in Tariff (REFIT) was developed by NERSA to support the introduction and development of renewable energy options. Phase 1 of this programme focuses on wind, concentrated solar, land-fill gas and small hydro plant. It is expected that 725MW will be built under this programme, of which 400MW would be wind capacity (less than 30% load factor), and the remainder (325MW) providing higher load factor capacity.

Decommissioning plant

After 2022 a number of older power stations will reach the end of their economic life (normally 50 years). The schedule of decommissioning is included in the plans with the expectation that additional capacity will be required to replace these stations. There are currently debates underway to extend the life of these power stations to 60 years. While economically this may be a preferable option to incurring additional capital expenditure for new plant, there are offsets such as efficiency gains from new plant as well as emissions related improvements. For the purposes of the current IRP we have not allowed for life extension.

In addition it is assumed that non-Eskom generation will be commissioned when they reach the end of their economic life (indicated in 2015 and 16).

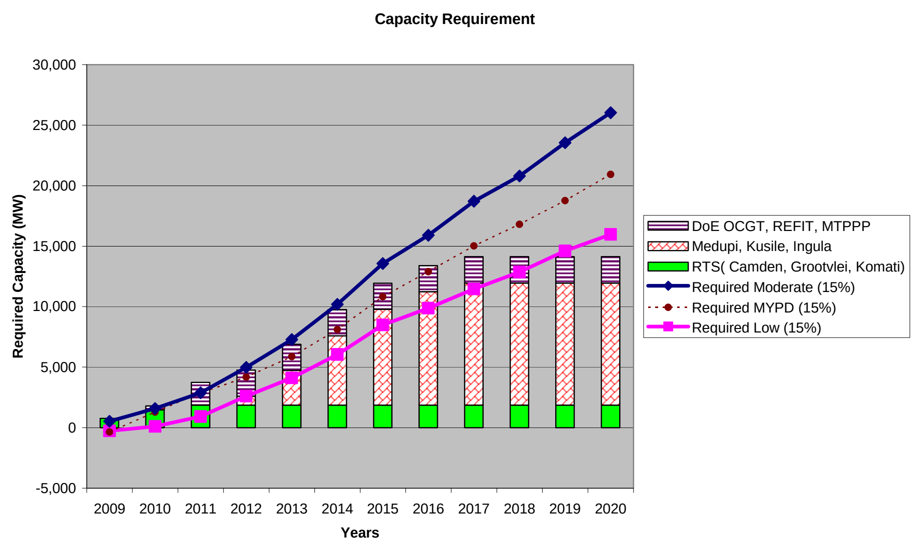
Demand-side interventions

For the purposes of the reference case the revised moderate forecast (or MYPD forecast) is used to indicate expected energy and demand. Details regarding the development of the revised moderate as well as the expectations regarding DSM programmes are included in Appendix B.

Capacity requirements

Figure 1 provides a simplistic view of the capacity required in each year from 2009 to 2020 to meet three different forecasts: the moderate forecast (and an assumed 15% reserve margin) as the top end of the cone; the MYPD forecast (with an assumed 15% reserve margin requirement); and the low forecast (also with an assumed 15% reserve margin requirement) as the bottom end of the cone. This requirement (in each case) is the demand required (with reserve margin) less the existing South African generation capacity (43 385MW). The projects currently under developed are indicated. These include the return to service (RTS); the base-load capacity under construction at Medupi and Kusile as well as the peaking capacity under construction at Ingula; and the IPP programmes represented by the DoE OCGT, the REFIT and the MTPPP programmes. These programmes (in various stages of commitment) fill the gap to some extent, but the graph highlights the shortfall throughout for meeting a 15% reserve margin on the moderate, or after 2017 to meet the reserve margin-adjusted MYPD forecast.

Figure 1 – System capacity requirement



This view is overly simplistic in that it excludes the energy constraints applicable to generators such as OCGT, pumped storage and hydro plants. The energy requirement would accelerate the need for additional capacity to a point before that reflected in this graph.

4. SCENARIOS

A number of scenarios have been contrived in order to incorporate policy objectives (and associated risks) not captured in the least-cost reference. The rationale and results from these scenarios are discussed below. The expectation is that the different scenario results will be assessed to determine a risk-adjusted IRP (as distinct from the least-cost reference IRP) to accommodate the policy considerations.

The scenarios are intended to address key policy issues that are not captured in the reference plan.

These include:

1. Greenhouse gas emission targets
   Given the heightened focus on climate change and the need to address greenhouse gas emissions (of which CO_2 is a particular concern for the electricity industry) the Department of Environmental Affairs has produced a Long Term Mitigation Strategy (LTMS). This strategy provides targets for, amongst

others, CO_2 emission reductions and mechanisms to achieve these. From an IRP perspective two modelling approaches have been adopted to deal with emissions:

a) Enforcing the Emission Cap

The emission target established in the LTMS is set at 550 million tonnes of CO_2 per year. Of this target it is expected that the electricity industry will be responsible for 50%, thus a target of 275Mt/a is assumed as a constraint for some of the plans.

b) Introducing a Carbon Tax

The carbon tax assumed in the LTMS is included in the carbon tax scenario. The tax starts at R100/t in 2009 escalating over time to R750/t after 2040. This is modelled as part of the costs of the generators, modelled as a shadow price for emissions.

2. Independent power producers

The policy direction from the DoE is the introduction of private participation in the electricity generation sector. The original target set was for 30% of new capacity to be from private generators. There are a number of competitive programmes underway to introduce IPPs with Eskom as the off-taker. Some of these have been discussed above as input into the reference plan (such as REFIT and MTPPP). In addition there is the multi-site base-load programme (MSBLP), an Eskom-run programme to attract bidders for base-load capacity with the expectation of 4500MW capacity. The Pilot National Co-generation Programme is expected to have 17MW awarded in the near future.

Eskom is also engaging in bilateral discussions with developers. By far the most advanced of these are Mmamabula and Moamba, for which there is sufficient information to include these in the studies.

3. Diversification of resources

During 2008 more than 85% of Eskom total production came from coal-fired sources. Given the heavy reliance on coal as a source of electricity, government has seen a need to move to alternatives, not only from an environmental perspective but from a security of supply imperative. The system faces a significant risk from an event affecting a single source, for example, escalating coal prices, or extreme weather impacting on coal supplies (as evident from the January 2008 crisis).

4. Security of supply considerations regarding limitations on imports

Increasing imports from the region, while supportive of regional development initiatives, could have an impact on security of supply, especially if these imports become a significant portion of the supply, and if there is not sufficient diversification between source countries.

5. Renewable energy production
The DoE has established a target for renewable energy production at a cumulative 10000 GWh by December 2013. Of this target 6000GWh is expected from on-grid electricity generation.

Two sets of scenarios have been developed. The Base scenarios (indicated in Table 4) incorporate two particular policy issues – greenhouse gas emission reduction and increasing private participation in electricity generation. The second set of scenarios (indicated in Table 5) propose two extreme cases on the policy issues – looking at excluding coal as a future option, focusing on nuclear and renewable energy (to different extents) and private and import power options. In addition a scenario was included to incorporate the risk-adjustments on the emission portfolio that were utilised in the multi-year price determination application submitted by Eskom to NERSA in September 2009.

Certain potential projects were not included in the reference case due to the low confidence in their completion. These include the second phase of the MTPPP, and import options such as Kudu and Mpanda Nkua. Some of these are included in the scenarios to test the impact on the results.

Table 4 – Base Scenarios for IRP

Scenario	Name	Conditions
1	Reference plan	Least-cost; direct costs only; limited project options
2a	Domestic emissions (Emission Constraint 1)	Hard constraint of 275Mt/a in all years Options should include Wind to 3200MW; CSP to 10000MW; Nuclear up to 33000MW; using Eskom cost assumptions
2b	Regional emissions (Emission Constraint 2)	Hard constraint of 275Mt/a domestic and 40Mt/a imported in all years Options as per 2a
2c	Delayed regional emissions (Emission Constraint 3)	No constraint before 2025, apply constraint of 275Mt/a domestic and 40Mt/a imported after 2025. Allow some advanced decommissioning or ramping down of existing coal options to reduce to hard target in 2025 Other options as per 2a
2d	Carbon Tax	Alter input costs to include carbon tax as per the Long Term Mitigation Strategy
3a	IPP alternates 1	Force in Mmamabula, Moamba, MSBLP
3b	IPP alternates 2	Force in Mpanda Nkua, MTPPP2 (over and above IPP alternates 1)

Table 5 - Investment planning scenarios

Scenario	Name	Notes
1	Least-cost	Reference plan
2	Lowest CO_2	• Force in additional REFIT (using Eskom cost assumptions), to assumed maximum build rate • Additional imports forced (Kudu 2016, Mpanda Nkua 2017, Moamba 2013) • Exclude coal, allowing nuclear to fill base-load requirements
3	Policy portfolio	• Force in additional REFIT (using Eskom cost assumptions), to slower build rate than Lowest CO2 • Additional imports forced (Kudu 2016, Mpanda Nkua 2017, Moamba 2013, Mmamabula 2014) • IPPs forced (MTPPP2, MSBLP, DME IPP + 2 more of same costs) • Exclude coal, allowing nuclear to fill base-load requirements
4	Risk-adjusted emission portfolio	• Emission limits applied in 2025 (as in Delayed Regional emissions) • Nuclear 1 ready in 2020, rest of nuclear build optional • Coal 3 forced (2017), rest of coal optional • Renewable, CCGT and import options as per Delayed Regional emissions Note: Similar derivation to the Capacity Plan determined for the Multi-year price determination.
5	Policy-adjusted IRP	Based on the risk-adjusted emission portfolio, but allowing for additional requirements from the DoE, including: • A nuclear fleet strategy after 2020 • Hydro imports from the region • Additional DSM (which would not displace other options at this stage)

An optimised (least-cost) expansion plan has been produced for each of these scenarios (except the policy-adjusted IRP), highlighting the options available under the prevailing conditions and constraints.

5. Results

The detailed optimal expansion plan for each scenario in available in Appendix C. These provide indications of the capacity required from each resource at the annual peak.

For the purposes of comparison a few indicators from the scenario plans are highlighted here. Further discussion of each plan is included in the application of the criteria (Chapter 6) in order to assess the plan provided the best fit to the country's objectives.

Table 6 – Scenario plan comparators

Scenario	Coal 3 start	Coal 4 start	Nuclear capacity	Imports (% of capacity) in 2028
Reference	2017	2019	0	1,9%
Domestic emissions	2018	2026	9900	1,9%
Regional emissions	2020	2026	3300	9,2%
Delayed emissions	2017	2021	4950	10,3%
Carbon tax	2021	2023	0	10,3%
Risk-adjusted emission portfolio	2017	2026	4950	10,3%
Policy-adjusted IRP	2017	2026	11550	7,6%
Increased option range 1	2019	2020	0	4,3%
Increased option range 2	2021	2023	0	8,6%
Low CO2 investment	-	-	16500	7,2%
Policy investment	-	-	14850	8,7%

Cost of the plan

Figure 2 illustrates the cumulative present value of costs associated with each plan. The costs included are the capital costs of new projects (excluding existing plant and committed plant such as Medupi, Kusile and Ingula) as well as the operating and fuel costs of all plant. Each of the plans show an increase in the last year of the study period. Since most of the plant will be continuing to produce for decades to come an appropriate comparison of the plans would have to include the full impact of each capacity option. Thus operating and fuel costs into perpetuity are discounted back to the final year and added to the cost of the plan.

Figure 2 – Present Value Cost of Scenario optimal plans

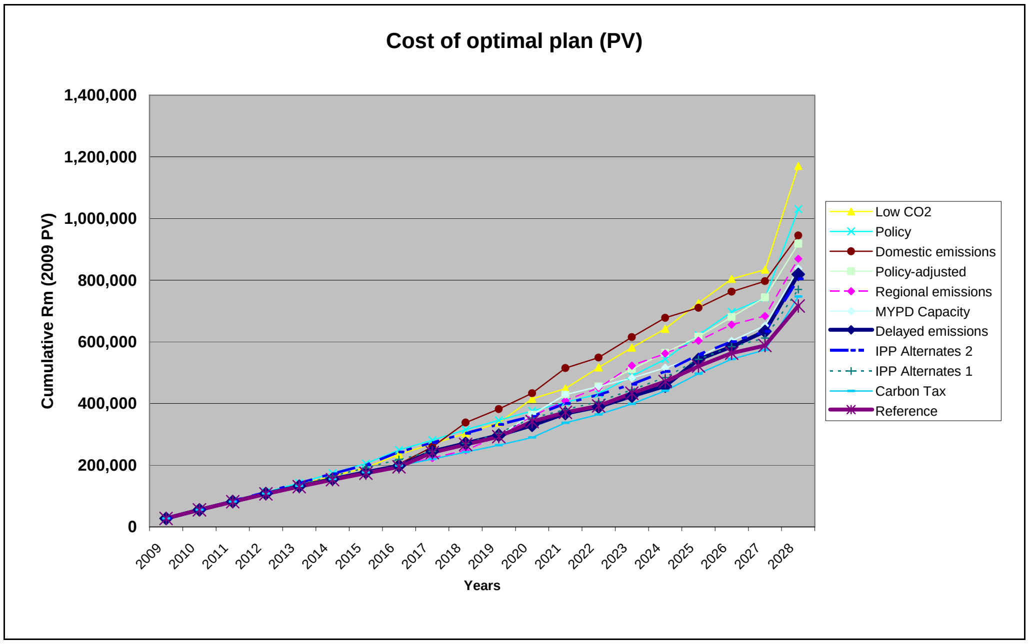
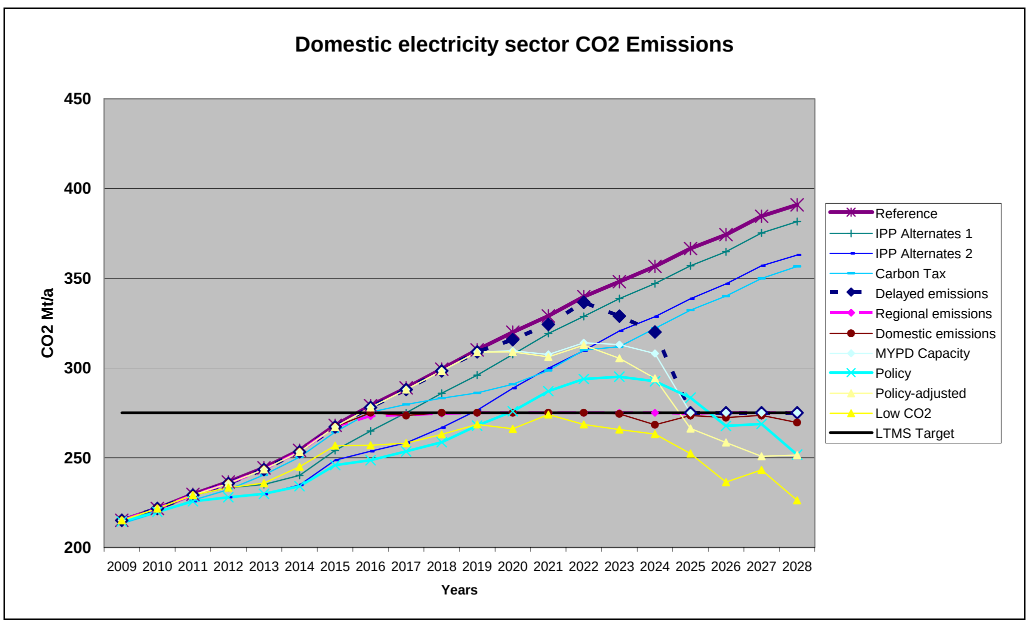


Figure 3 – Greenhouse gas emissions from scenario plans



Security of supply

Figure 4 illustrates the annual reserve margin for each of the scenarios based on the full capacity of each project. For a number of potential projects, especially renewable energy sources, the capacity has a low probability of being available for the annual peak (thus unlikely to contribute to the reserve margin). The capacity associated with these "non-dispatchable" sources have been de-rated (for wind to 5% of its capacity; for solar to 50% of its capacity; and for some hydro options to 80% of its capacity). For a more accurate comparison, Figure 5 demonstrates the reserve margin in each scenario using the de-rated capacity. Each of the scenario plans experiences a reduced reserve margin (due to the impact of REFIT projects amongst others) while scenarios utilizing more renewable energy have a more pronounced reduction in "reliable" reserve margins. The impact of this reduced capacity contribution is captured in the risk factor criterion (described in Appendix D) which provides a means to discount plans which introduce additional risk to the system.

Figure 4 – Reserve Margin (full capacity contribution)

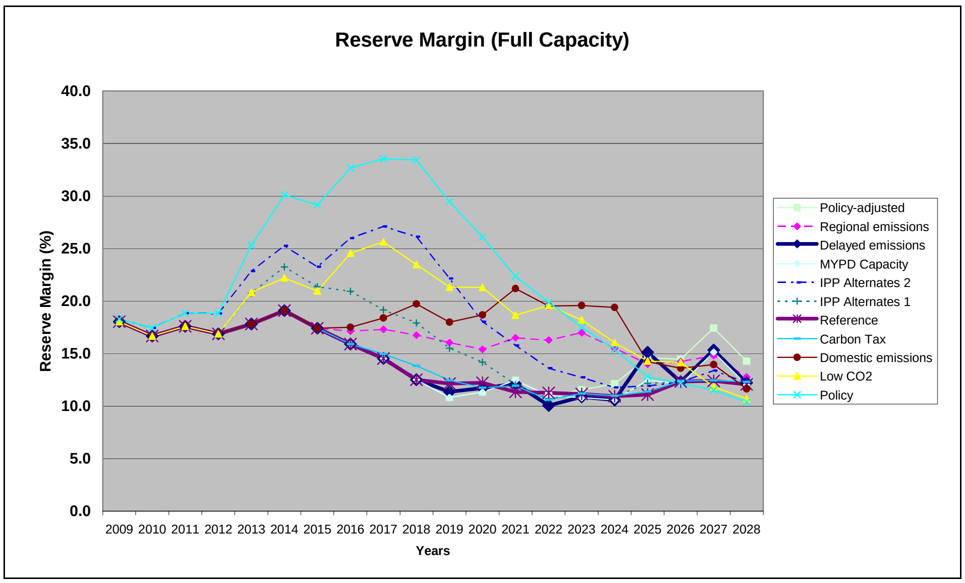
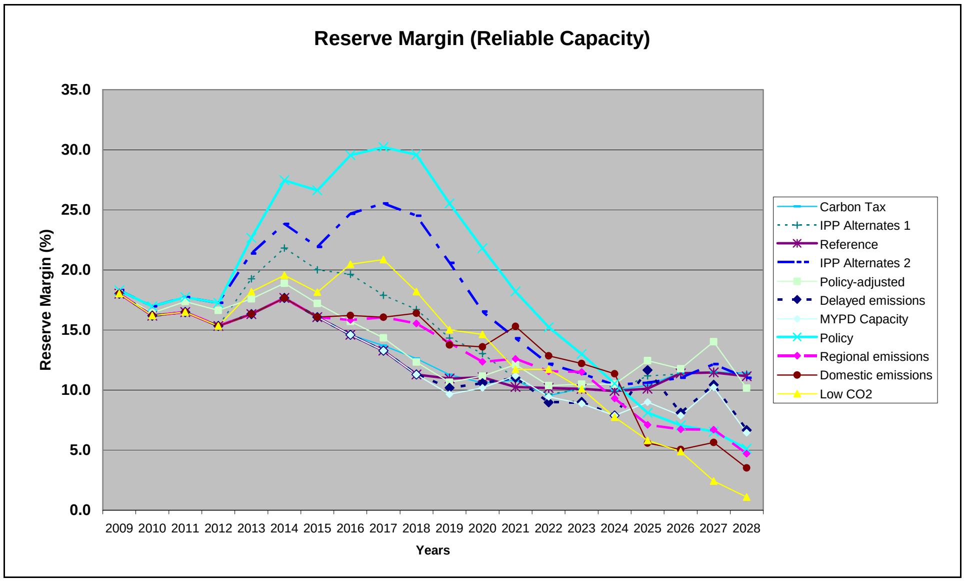


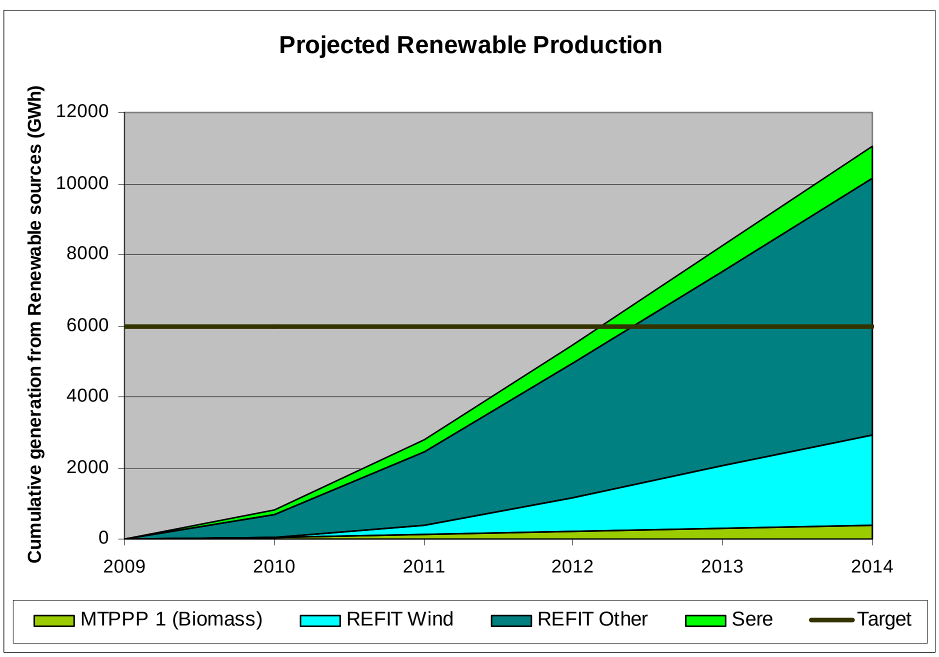
Figure 5 – Reserve Margin (reliable capacity contribution)



Renewable energy

The assumed capacity targets for the REFIT programme provide sufficient capacity to meet the government's renewable production target of 6000GWh. This is common to all the plans. Additional renewable energy is developed under the emission scenarios and investment portfolio scenarios alongside the switch to nuclear energy for base-load capacity.

Figure 6 – Renewable energy production



6. APPLICATION OF CRITERIA

6.1. Goodness of fit

The criteria, as described in Appendix D, describe the dimensions in which the optimal scenario plans can be assessed for "goodness of fit". The principle is to achieve the best outcome to meet stakeholders' objectives, no matter how much in conflict these objectives may seem.

By following a rigorous multi-criteria decision making (MCDM) approach it is possible to describe, numerate and score the preferences and values of the stakeholders with respect to each of the criteria. This provides a solid foundation to choose a single plan as the preferred option. In addition it is possible to identify next-best alternates that can undergo additional stress testing to incorporate concerns regarding robustness to sensitivities. This latter stage is described in Section 7, once the preferred plan is identified.

Table 7 – Risks associated with specific projects

Risks	PS	PF Coal	MTPPP2	Mmamabula	Moamba	OCGT	Wind	Small hydro	FBC	DoE OCGT	Nuclear	Mpanda Nkua	CCGT	MSBLP	Kudu	CSP
Confidence in cost assumptions																
Confidence in technology																
Confidence in timing																
Confidence in reliability																
Safety concerns																
Resource concerns																
TOTAL	**2**	**3**	**3**	**3**	**3**	**4**	**4**	**4**	**5**	**5**	**5**	**6**	**7**	**8**	**9**	**10**

The criteria selected for the evaluation of "goodness of fit" are:

1) CO_2 emissions, with the average annual CO_2 emissions (in million tonnes) for the study period serving as the metric;
2) Plan cost, with the normalised present value total cost of the plan (indexed to the cheapest plan – the reference plan) as the metric;
3) Diversity, with the coal-fired generation sent-out in 2028 as a percentage of the total generation sent-out in 2028 as the metric;

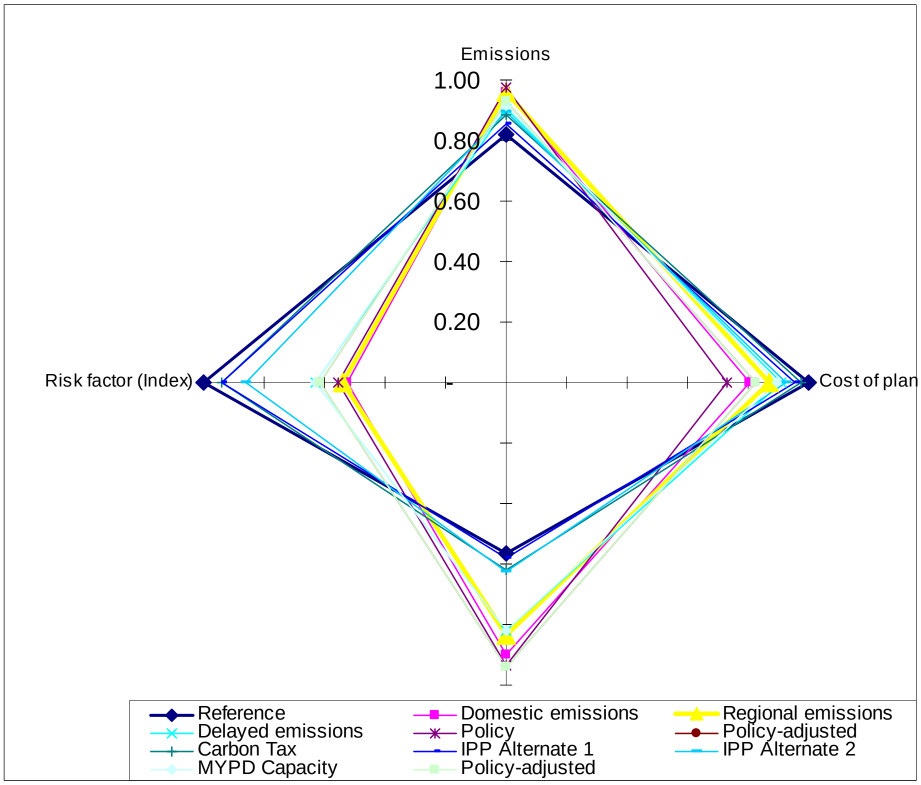
4) Risk factor, with the index of risk factors associated with constituent projects (weighted according to capacity contribution to the plan) as the metric.

Figure 7 provides indications of the results for each scenario. The metrics as provided in Table 8 are normalised, with the best result for each criteria scoring 1.0 and decreasing with worsening results for the specific criteria. For example the Low CO_2 scenario, which scores the best in terms of emissions and diversity, scored the worst (by some margin) on both the cost and risk criteria.

Table 8 – Metrics for criteria (results from optimization)

Plans	Domestic CO2 emissions (MT)	Normalised PV cost of plan	Coal-fired gen (% of total in 2028)	Risk factor associated with projects
Reference	302.82	**1.00**	92.33	3.1
Domestic emission (Emission 1)	261.04	1.32	61.71	**6.2**
Regional emission (Emission 2)	261.82	1.21	67.67	6.1
Delayed emission (Emission 3)	278.22	1.14	69.05	5.5
Carbon Tax	284.14	1.04	87.60	3.5
IPP Alternative 1	293.50	1.08	90.94	3.5
IPP Alternative 2	280.43	1.12	86.84	4.0
Risk-adjusted emission portfolio	274.56	1.17	69.05	5.5
Policy-adjusted IRP	269.66	1.28	57.98	5.6
Policy	257.14	1.44	58.44	6.0
Low CO2	**248.96**	1.63	**52.30**	6.5
	Average domestic emissions (2009-2028)	*Total PV cost of the plan (2009-2028), normalised to reference*	*Percentage of total production in the year 2028*	*Weighted average of project risk factors (by capacity contribution)*

Figure 7 – Normalised criteria results for each plan



6.2. Partial value functions

Having determined the metric results for each of the potential plans a partial value function is constructed to map these results to a value representing the preferences of decision-makers. The partial value function is important in providing a precise mechanism to rank the outcomes of the different plans in a particular criterion according to the decision-maker preferences. While this process should include a broad range of stakeholders to capture all the preferences this requirement could not be met for the current iteration and a smaller group of Eskom experts assisted in determining the value functions for each criterion.

These value functions are provided in Appendix E with explanations. For the purposes of the scoring of the plans though, the results are indicated in Table 9. This shows how each plan has scored according to each criterion (with 100 being the best score, and 0 being the worst).

Table 9 – Partial value function results

Plans	CO2 emissions	Cost of plan	Diversity	Risk factor
Reference	-	100.00	-	100.00
Domestic emissions	92.82	61.37	96.24	19.61
Regional emissions	92.36	75.34	85.82	26.14
Delayed emissions	69.22	84.35	83.20	60.46
Carbon Tax	54.54	95.29	17.96	97.39
IPP Alternate 1	28.79	91.79	5.28	97.39
IPP Alternate 2	63.74	86.54	20.85	93.79
Risk-adjusted emission portfolio	76.68	81.25	83.20	60.46
Policy-adjusted IRP	82.87	66.40	97.73	57.19
Policy	95.14	40.18	97.55	32.68
Low CO2	100.00	-	100.00	-

6.3. Swing weighting

A critical component of the Multi-criteria Decision Making process is to determine weightings for each of the criterion. This provides the mechanism to score the plans across the different criteria.

In order to determine the weighting for the criteria a series of hypothetical cases are evaluated in which a plan scores best on each of the criteria and worst on all the others. Taking each of these hypothetical plans a preference ranking can be determined to indicate the extent to which one criterion is more important than others and how the other criteria relate in importance to one another. The highest priority gets an arbitrary weighting of 10 and the others are ranked in relation to the top score of 10.

In the process followed for this IRP, the weightings were resolved as:
- Cost of plan (Weighting 10)
- Emissions (Weighting 7)
- Risk factor (Weighting 5)
- Diversity (Weighting 3)

6.4. Scoring

Having calculated the importance weighting between the criteria and the partial value functions within each criterion a final value associated with each plan was produced. This result, indicated in Table 10, is determined by multiplying the partial value result for each criterion by the weighting (as a percentage of the total weighting for all criteria). Thus the Reference plan, having scored 100 on the cost and risk factor criteria, achieves a score of 60 (0.4*100 for the cost criterion, 0.2*100 for the risk factor criterion), having no score for emissions or diversity.

Table 10 – Final value score for plans

Plans	CO2 Emissions	Cost of plan	Diversity	Risk factor	TOTAL
Reference	-	40.00	-	20.00	60.00
Domestic emissions	25.99	24.55	11.55	3.92	66.01
Regional emissions	25.86	30.13	10.30	5.23	71.52
Delayed emissions	19.38	33.74	9.98	12.09	75.20
Carbon Tax	15.27	38.12	2.16	19.48	75.02
IPP Alternate 1	8.06	36.72	0.63	19.48	64.89
IPP Alternate 2	17.85	34.61	2.50	18.76	73.72
Risk-adjusted emission portfolio	21.47	32.50	9.98	12.09	76.04
Risk-adjusted IRP	23.20	26.56	11.73	11.44	72.93
Policy	26.64	16.07	11.71	6.54	60.95
Low CO2	28.00	-	12.00	-	40.00
Weighting	0.28	0.4	0.12	0.2	100
	7	10	3	5	25

Thus, from the multi-criteria decision analysis, it would appear that the risk-adjusted emission portfolio plan is preferable to the others, followed closely by the Delayed emission scenario and the carbon tax scenario.

While the three emission plans (especially the domestic emission plan) score best on emissions and diversity, this is offset by the higher cost of these plans and the increased risk profile. The MYPD risk-adjusted emission portfolio plan closely follows the delayed emission plan but brings forward Nuclear and CSP options. This increases the cost marginally (thus scoring less on the cost criterion) but improves the emissions. As opposed to the regional emissions the emission portfolio plan is worse on the emissions but significantly better on risk and marginally better on cost. Thus the increased risk associated with options in the regional and domestic emission plans impede their scoring.

Further tests on these plans, especially regarding robustness and price paths, follow. But due to resource and time constraints only the Reference plan and the risk-adjusted emission portfolio plan (the latter being the best scored from the MCDM process) have been tested in these dimensions.

7. RISKS AND UNCERTAINTIES

7.1. Sensitivity Studies

Even with the policy and growth uncertainties to some extent catered for in the scenarios listed above, there are a number of other uncertainties that need to be considered. The models have been tested against changes in the underlying assumptions regarding, in particular:

- Changes in the energy forecast;
- Plant failure leading to sustained higher than targeted plant outage; and
- Uncertain and prolonged lead times and cost for building new plant.

In order to test for these uncertainties, the following process was followed on the reference case. (It was assumed that similar responses would be required from the risk-adjusted emission portfolio case as it has similar expansion options in the early period; and consequently similar responses would be found in each case. Due to time and resource constraints the process was not repeated for these and the other plans.)

i. The development of Coal 3 was taken as a given (i.e. would not shift with changes in demand);
ii. For the lower forecast sensitivity, the ISEP12 Low forecast was used, and all further expansion options allowed to be optimised;
iii. For the higher forecast sensitivity, the original ISEP12 Moderate forecast was used, allowing OCGT options after 2013 (with a maximum 7 units per annum), and new coal options only after 2018 (maximum 2 units in 2018, optimum thereafter).

The results indicate that an increase in the actual demand to the ISEP12 Moderate forecast would lead to substantial capacity from OCGT being developed to fill the capacity gap before 2017; thereafter the base-load coal requirement can be met with accelerated coal projects. If the actual demand were to be closer to the ISEP12 Low forecast all capacity would be deferred significantly (as one would expect).

Figure 8 – Sensitivity impact on reference plan

Scenario		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Capacity (MW)
Reference MYPD	Coal				1	2				3		4	5			6	7	8,9				37326
	OCGT											2				3			4			2940
Reference on ISEP Moderate forecast	Coal				1	2				3	4	5,6					7,8	9,10				42324
	OCGT					2	3	4	5												6	4410
Reference on ISEP Low forecast	Coal				1	2				3							4	5,6,7				27330
	OCGT															2	3					1176
Reference 83% EAF	Coal				1	2			3	4					5	6	7	8,9			10	38754
	OCGT								2							3	4		5			3822

7.2. *Production performance*

Validation through producing a production plan

THIS IS CURRENTLY UNDERWAY

7.3. *Key risks in the IRP*

While the risk factor criterion provides a mechanism to evaluate the potential plans for the inherent risks of each plan, it is worth highlighting the risks to provide focus for possible mitigation.

In each of the plans there is a series of common concerns that occur due to the assumptions made up-front. These include:

- Worse performance from the Eskom base-load fleet
  As the stress tests above indicate, if the assumption of 86% EAF does not hold for Eskom's generators the system would be at risk from a reduced reserve margin with limited ability to rectify in the medium term
- Reduced contribution from non Eskom power stations
  Similarly to the reduced availability of Eskom power stations, if non Eskom generators produced less than the assumed capability the expected reserve margin would not materialise.
- Performance and modelling of renewable options
  The impact of renewable capacity is highly uncertain given the limited exposure to these technologies in South Africa. This is partly mitigated by the relatively small volumes expected in the medium term, but with larger and more numerous projects improved modelling techniques and forecasting will be required.
- Load forecast

The actual energy requirement is certain to deviate from the forecast, erring either on the upside or downside. If the forecast is understated the capacity shortfall could be problematic given long lead-time to react. Conversely, an over-estimation would have economic impact of unnecessary capital expenditure.

- Current Eskom build programme
  The risks of delays in the current build programme have a significant impact on the ability to meet demand reliably in the medium term.
- Transmission expansion
  The plans all assume that the Transmission grid would be able to expand to meet the required energy demand, as well as the geographic spread of new capacity. Some allowance is made for the lead times for new Transmission capacity, but significant delays in securing servitudes or similar limitations would impede on the ability to execute the plan optimally.

As indicated in the risk factors there are issues specific to each of the plans. For the purposes of illustration the specific issues for the reference plan and the risk-adjusted emission portfolio plan are discussed further.

a) Reference plan
   - The prime concern for the reference plan, in terms of risk factors, is the limited resources available in terms of water supply and sorbent. The water conditions, especially in the Waterberg where much of the new coal-fired capacity is expected, is problematic. Additional water infrastructure will be required to meet the water needs for new projects in the Waterberg. In the long run there will be a national water deficit requiring desalination.
   - The availability and transport of sorbent for flue gas desulphurization (FGD) is also a concern, including the waste management for the resulting by-products.

b) Risk-adjusted emission portfolio plan
   - Chief among the concerns for this plan is the untested nature of the technologies that would contribute to the reduction in greenhouse gas emissions. In particular the Concentrated Solar Power projects have not had extensive commercial use world-wide as yet and cost estimates are ball-park at best.
   - The nuclear programme as posited carries risks associated with the technologies, lead-times required as well as the cost estimations. It has been suggested that a nuclear fleet strategy would see cost reductions for the subsequent projects, but this possibility would need to be tested.
   - While a nuclear strategy would alleviate some of the pressure on water resources, current estimates suggest CSP projects require a similar amount of water (per MWh

production) as dry-cooled PF coal. Considering that the best location for the CSP is in the north west of the country, which happens to be the driest part of the country, this consideration is not trivial.

- Additional imports to assist in alleviating the pressure on South Africa's emission targets carry additional risk in terms of energy security. While these volumes are still less than the reserve margin, the increased risk is cause for concern.
- The development of a viable CCGT option is dependent on either LNG supply or underground coal gasification. Either is dependent on other developments still far from certain. If neither comes to fruition alternatives would be required.

8. RECOMMENDED EXPANSION PLAN

After considering the criteria determined above and undergoing the fairly rigorous MCDM process, the risk-adjusted emission portfolio plan seems to be the best of the scenario plans considered.

Having proposed this plan to the DoE, additional policy adjustments have been requested. These include:

- Allowing for additional demand-side interventions, especially the million solar water geyser target set by the Minister of Energy;
- Following a nuclear fleet strategy; and
- Incorporating additional hydro potential from the region.

The capacity and energy savings brought in by the solar water geyser target was estimated and included in the IRP, along with a shift in base-load from gas and coal imports to domestic nuclear and hydro imports. These changes are reflected in the policy-adjusted IRP below:

Table 11 – Proposed Policy-adjusted IRP

	Committed	Coal 3	Coal 4	Coal 5	Nuclear fleet	CCGT	CSP (Generic)	Import hydro	Kudu	Moamba	OCGT	Total new build	Total system capacity	Total DSM (incl DoE SWH project)	Peak demand (net sent-out) forecast (after DSM)	Reserve Margin
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
2009	772	0	0	0	0	0	0	0	0	0	0	772	44157	432	37413	18.03
2010	1156	0	0	0	0	0	0	0	0	0	0	1156	45313	923	38509	17.67
2011	1997	0	0	0	0	0	0	0	0	0	0	1997	47310	1343	39571	19.56
2012	1022	0	0	0	0	0	0	0	0	664	0	1022	48996	2118	40255	21.56
2013	2127	0	0	0	0	0	0	0	0	0	0	2127	51123	3056	41182	23.98
2014	2865	0	0	0	0	0	0	0	0	0	0	2865	53988	3935	42576	26.65
2015	2024	0	0	0	0	0	0	0	0	0	0	2024	56012	4225	44939	24.50
2016	1381	0	0	0	0	0	0	0	0	0	0	1381	57393	4525	46744	22.64
2017	723	714	0	0	0	0	0	0	0	0	0	1437	58830	4825	48586	21.03
2018	0	714	0	0	0	0	0	0	0	0	0	714	59544	5125	50134	18.79
2019	0	714	0	0	0	0	0	0	0	0	294	1008	60552	5425	51840	16.90
2020	0	714	0	0	1650	0	0	0	0	0	0	2364	62916	5425	53720	17.00
2021	-75	714	0	0	1650	0	184	0	0	0	0	2473	65389	5425	55362	17.91
2022	0	714	0	0	0	0	368	0	0	0	0	1082	66471	5425	57093	16.52
2023	-909	0	0	0	1650	786	552	0	0	0	294	2373	68844	5425	58921	16.97
2024	-1424	0	0	0	1650	786	552	500	0	0	294	2358	71220	5425	60728	16.99
2025	-2740	0	0	0	1650	786	552	500	2358	0	0	3770	74344	5425	62666	18.01
2026	-2280	0	1428	0	1650	0	552	500	0	0	147	1997	76359	5425	64517	17.53
2027	0	0	714	714	1650	0	1104	0	0	0	0	4182	80541	5425	66391	20.23
2028	-2850	0	714	714	0	0	1104	0	0	0	0	-318	80223	5425	68007	16.86

Economic impact of the IRP

- Reference plan
- Risk-adjusted emission portfolio plan

THIS IS STILL OUTSTANDING

Price path of each plan

- incremental impact on financing (especially marginal impact of nuclear relative to coal)

THIS IS CURRENTLY UNDERWAY

9. FUTURE RESEARCH

In the process of developing this IRP a number of shortcomings in the current process have been identified. It is strongly recommended that the next iteration of the IRP incorporate the following elements as much as possible, or at least make progress in incorporating them in future iterations:

- further integration with transmission expansion
- regionalising the planning results, including regional load forecasting
- increased focus on water constraints, both from the national and regional perspectives, as well as the necessary infrastructure to meet regional requirements
- increasing public participation in the process
- development of additional criteria, especially those put aside in this iteration due to the lack of information or definition
- further understanding on climate change and mitigation
- further understanding on potential technologies

10. CONCLUSION

The current IRP process has different from previous iterations (both within and external to Eskom) in that there has been:

- increased stakeholder and customer involvement in the process, especially government departments and industry consumer groups;
- the integration of policy objectives, in particular, emissions and diversity;
- the establishment of criteria and a mechanism to evaluate the plans according to these;
- the reconstitution of appropriate governance structures and processes to involvement from different divisions within Eskom;
- improved transparency from initial steps to create an energy planning database;
- the testing of robustness and flexibility of the plans.

In conjunction with the recommended IRP the following considerations should be noted that:

i) Having been based on the revised moderate forecast, the IRP must be flexible to cope with the higher demand reflected in the ISEP12 Moderate forecast as well as the lower demand reflected in the ISEP12 Low forecast;

ii) The nuclear programme is assumed on a project-by-project basis, starting with the first station in 2020;

iii) There is space for IPP participation, especially with the MSBLP, Moamba and/or Moamba, and that the Coal 3 start in 2017 can be delayed with a successful implementation of any of these programmes. However Coal 3 preparation should continue (including water and transmission infrastructure) until clarity is achieved on the IPP programmes;

iv) The emission target needs to be confirmed, and the rules regarding its implementation finalised, especially the approach of "exporting" approximately 30Mt/a of emissions to neighbouring states.

The following conditions should be fulfilled to ensure the success of the IRP in meeting the needs of the country:

- The development and commercialisation of renewable energy alternatives, in particular Concentrated Solar Power (CSP), which – at assumed cost calculations – would offer an effective mid-merit power source with reduced emissions;
- The development of a nuclear strategy to provide low emission base-load alternatives to coal-fired generation from 2020;
- Continued investment in the maintenance and refurbishment of existing Eskom (and non-Eskom) plant to ensure generator performance at assumed levels;
- Continued investment in demand side management initiatives to improve energy efficiency and delay additional capacity requirements. This includes the expected load reduction stemming from the Department of Energy's one million solar water geyser target.

APPENDIX A - SUPPLY RESOURCES

A.1. EXISTING RESOURCES - Eskom

Coal

Coal considerations…

Capacity
Availability stats
Fuel issues

Pumped Storage
Hydro
Open Cycle Gas Turbine

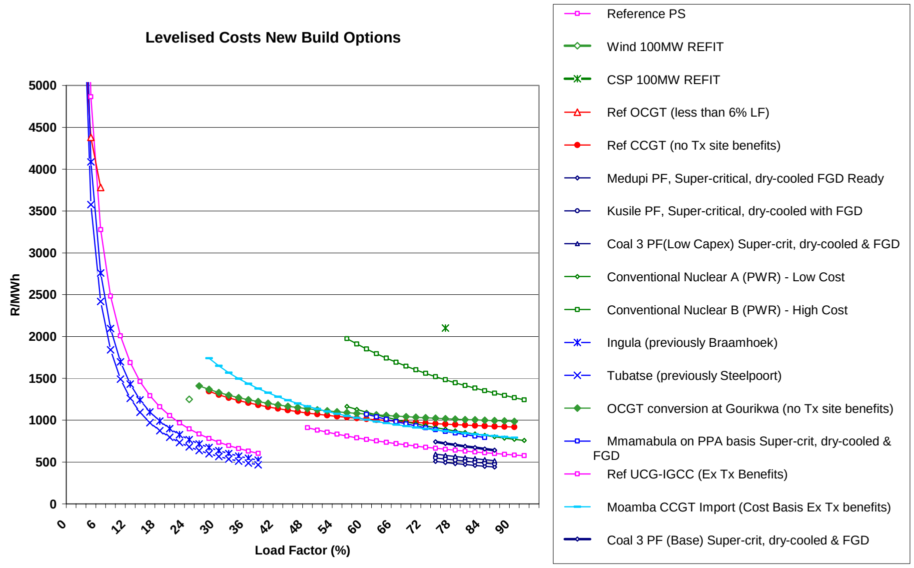
A.2. EXISTING RESOURCES – Non-Eskom

Municipal
Self-generation
Imports

Decommissioning

A.3. NEWGEN OPTIONS

SCREENING CURVES



Pulverised Coal fired plant

The basic features, description and operation of a PF coal fired plant can be illustrated as in

Figure 9 below. The integrated operation of these components can best be explained by describing the two processes of the, the steam generating cycle and condensing; and cooling cycle as follows:

- Steam generating cycle

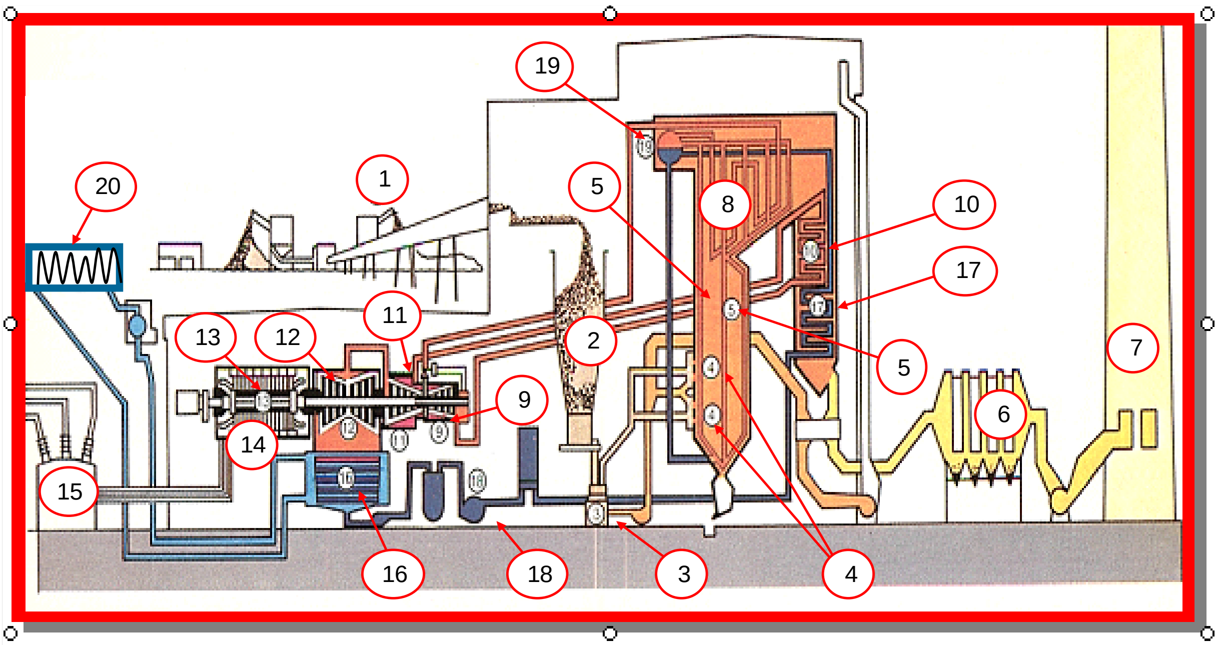
The primary energy source (coal) from the mine (1), through some elaborate processes, is fed to the mills (3) via the coal bunker / silo (2) that acts as storage feed. The millers pulverise the coal into a fine powder. The combustion of fuel (coal) takes place in the furnace (5) controlled by the boilers burners (4). The powdered coal is blown into the boiler furnace with air where it burns. The atmospheric air is provided by the forced draught fans pre-heated to approximately 250ºC. The temperature inside the furnace is ± 1200ºC at full load. The boiler exhaust flue gasses are used to preheat the water entering the boiler (17) first and then via the pre-heat steam tubes (8). The steam enters the re-heaters at a pressure of 4.2 MPa and a temperature of 330ºC. These exhaust flue gases then pass through the bag Filters or Precipitators (6) for ash removal and then the 275 m tall smoke stack (7) as they are emitted into the atmosphere.

A chemical energy conversion process generates heat to convert water into steam at a very high temperature (360ºC to 535ºC) and pressure (17MPa). The water is very pure demineralised water. The steam then cycles via the high pressure (HP) turbines (9) then to the re-heating steam tubes (10) before feeding into the Intermediate pressure (IP) turbine (11) at a temperature of 535ºC and a pressure of 3,9 MPa. The exhaust steam from the IP turbine, at 0,29 MPa and 204ºC, flows to the last part of the cycle where it expands through two large double flow low-pressure (LP) turbines (12). The spent steam from the LP turbines is at pressures of between 6 and 7 kPa (absolute) and a temperature of ±40ºC. Typically each of the turbine stages contributes to the total output of the generator. The HP turbine delivers 25%, the IP turbine 45% and the two LP turbines deliver 15% each. Coupled to the turbine shaft is a generator rotor (13) which produces electrical energy as it cuts the flux (magnetic field) of the stator (14) thus inducing electrical energy that flows via cables to the LV side of the step-up transformer (15).

- Condensing and Cooling Cycle

The steam condenser (16) is a shell filled with typically 32,000 brass tubes. The spent steam from the turbine enters the shell and comes into contact with the cold outer surfaces of the tubes. Water from a cooling water system flows through the tubes. As a result of the difference in temperature between the spent steam (approximately 34ºC) and the cold water (19ºC) condensation is achieved. Cooling water is supplied to the individual condensers by the cooling water supply pumps at a rate of 5 m³ / second.

Figure 9: Simplified Basic features of a Dry cooled Pulverised Fuel coal Fired Plant



Fluidised Bed Combustion (FBC) Power Generation Systems

FBC boilers are capable of burning a range of different fuels including all ranks of coal (including high ash coal), coal wastes (i.e. discard coal), coke and biomass. In FBC, solid fuels are suspended in upward blowing jets of air resulting in turbulent mixing of gas and solids. This enables more effective chemical reactions and heat

transfer. Combustion occurs between 800 – 900oC, well below the threshold for NOx formation. Sulphur pollutants are reduced by the injection of a sorbent (limestone or dolomite) into the bed and subsequently the removal of ash together with the reacted sorbent. This is a particularly important feature of the technology. FBCs can potentially improve the environmental impact of coal-based electricity, reducing SOx and NOx by up to 90%.
Two types of FBCs exist namely Bubbling Fluidized Bed Combustion (BFBC) and Circulating Fluidized Bed Combustion (CFBC). BFBCs use a low fluidising velocity with the intention that particles are held mainly in a bed, conversely CFBCs use a higher fluidizing velocity so that the particles are constantly held in flue gases.

BFBCs and CFBCs have two subgroups, non-pressurised (operating at atmospheric pressures) and pressurised (typically operating at 12-16 bars) systems. Generally BFBCs are used in small plants offering a non-pressurised efficiency of around 30% and CFBCs used for much larger plants offering efficiencies of over 40%. 1st generation PFBCs use “bubbling-bed” technology and 2nd generation uses “circulating-fluidized bed” technology. The more dominant type of FBC units are CFBCs and units with generating capacities of up to 300MW are currently in operation. Those in commercial application are generally atmospheric with subcritical steam turbines although there have been a number of pressurized CFBC pilot scale investigations to assess the possible advantages of reductions in unit size. The world’s first supercritical CFBC unit is under construction in Poland. It is 460MW with supercritical steam conditions of 27.5MPa/ 560oC/580oC. The net plant efficiency is specified to be 43.3% (LHV) or 41.6% (HHV).

CFBCs (atmospheric, subcritical) are established and can be considered as mature alternatives to PF (Pulverised Fuel) boilers. Heat rates between PF and CFBC boilers of the same size, steam conditions and fuel are comparable. The heat rate will however be higher for CFBC units designed to operate using lower grades of coal. Because CFBCs use coal crushed to around 3 to 6mm and PFs use coal that has been crushed to a fine powder, the energy and facility requirements for CFBC coal preparation are much less.

Figure 10 & Figure 11 below show diagrammatic illustrations of BFBC and CFBC respectively.

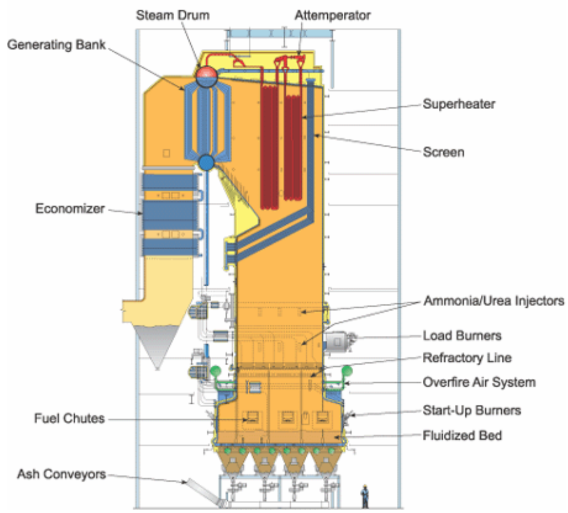


Figure 10 – Simplified illustration of a BFBC boiler

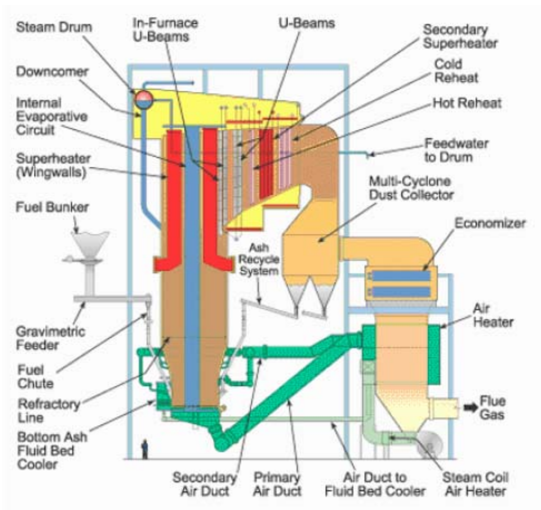


Figure 11 – Simplified illustration of a CFBC boiler

Nuclear

The nuclear power industry has been developing and improving reactor technology for almost five decades. Several generations of reactors are commonly distinguished in the following manner:

- Generation I reactors were developed in the 1950-60s. Outside the UK none are running today.
- Generation II reactors are typified by the present US fleet and are in operation in most other countries.
- Generation III/III+ reactors are the advanced generation II reactors largely due to safety enhancements to the Generation II reactors. These reactors are currently being constructed in Japan, Finland and China.
- The greatest departure from Generation II designs is that many Generation III reactors incorporate passive or inherent safety

features which require no active controls or operational intervention to avoid accidents in the event of malfunction, and may rely on gravity, natural convection or resistance to high temperatures. Many are larger (in size and capacity) than their predecessors.

- Generation IV designs are still on the drawing board and will not be operational before approximately 2025.

To ensure that nuclear power remains a viable option in meeting energy demands in the near future, new reactor designs are being developed in a number of countries. Common goals for these new designs are high availability, user-friendly features, competitive economics and compliance with internationally recognized safety objectives. Development of advanced designs is proceeding for all reactor lines - water-cooled reactors, gas-cooled reactors, and liquid metal cooled reactors. Global trends in advanced reactor designs and technology development are periodically summarized in status reports prepared by the IAEA.

As such, the following are the salient features of generation III/III+ reactors:

- a standardised design for each type to expedite licensing, reduced capital cost and reduced construction time,
- a simpler and more rugged design, making them easier to operate and less
- vulnerable, to operational upsets,
- higher availability and longer operating life - typically 60 years,
- reduced possibility of core melt accidents,
- minimal effect on the environment,
- higher burn-up to optimise fuel use and reduce the amount of waste,
- burnable absorbers ("poisons") to extend fuel life.

Several Nuclear Power Plant (NPP) types are used for energy generation and are usually classified based on the main features of the reactor applied in them. The main power plant reactor types currently in operation in the world today are:

- Light Water Reactors (LWR)
- Heavy Water Reactors (HWR)
- New Generation Reactors (Generation IV)

The Eskom study to include Nuclear Power in its generation mix converged on generation III/III+ reactors; viz. LWR and HWR. Generation IV reactors were not considered as it is still in the developmental stage. Hence, in the pre-feasibility phase, Eskom evaluated 5 reactor types; viz. RSA 1000, EPR, AP1000, CANDU, ABWR.

On evaluation of the vendors that supply the above reactors (who are all leaders on nuclear power plant design and have reputable global project deployment history), it was observed that any of the five plant types investigated could reliably and safely introduce power into the Eskom grid. The selection of any of the above technologies would prove less risky than any Generation IV Nuclear reactor which, when constructed, will be a First of a Kind Engineering (FOAKE) plant. It is extremely risky to deploy a nuclear plant that is not proven.

This resulted in the AP1000, the EPR and the RSA 1000 technology plants being short listed for further consideration. Recent interaction with potential suppliers indicated reluctance to manufacture and supply the RSA 1000. Suppliers indicated that due to improved regulatory safety standards it would be difficult to license the plant that is classed as Generation II technology.

Therefore, it was recommended that two plant types i.e. AP 1000 (1140MWe) and EPR (1650MWe) with the respective suppliers be taken further into Eskom's investment and procurement processes for the development of the Nuclear-1 project.

The AP1000 technology is a Generation III/III+ design and has recently been procured by the Chinese. The EPR has a complete design and have customers, EDF in France, and is also under construction by TVO in Finland.

Pumped Storage

CSP

The amount of sunlight that hits the Earth's surface in one hour is enough to power the entire world for a year. The underlying advantage of solar energy is that the fuel is free, abundant and inexhaustible. It provides the best, clean and cheap opportunity to the sunniest countries of the world to use solar energy to generate power.

Eskom is investigating the use Concentrating Solar Power (CSP) technology due to the following reasons:

- The solar radiation reaching the surface of the earth is very dilute about 1 kWh per square meter
- Solar radiation is distributed unequally over the surface of the earth
- Intermittent; thus it solves the irregularity of solar power availability, which fluctuates with cloud cover and nightfall
- CSP converts solar power into thermal energy and in this way this power can be stored and deployed whenever needed
- The ability to store solar energy as in above makes it viable as a source of base load powder

There are two types of CSP technologies and they are namely concentrating photovoltaic and concentrating solar thermal.

Concentrating Photovoltaic (CSPV)

CSPV typically use lenses and mirrors to concentrate light on solar cells to maximize the amount of electricity they can generate and they have tracking systems that mount the solar arrays track the sun during the day to maximise light input. The disadvantage of this technology is that the efficiency of cells degrades at high heat and can damage and destroy equipment at very high temperatures.

CSP Technologies

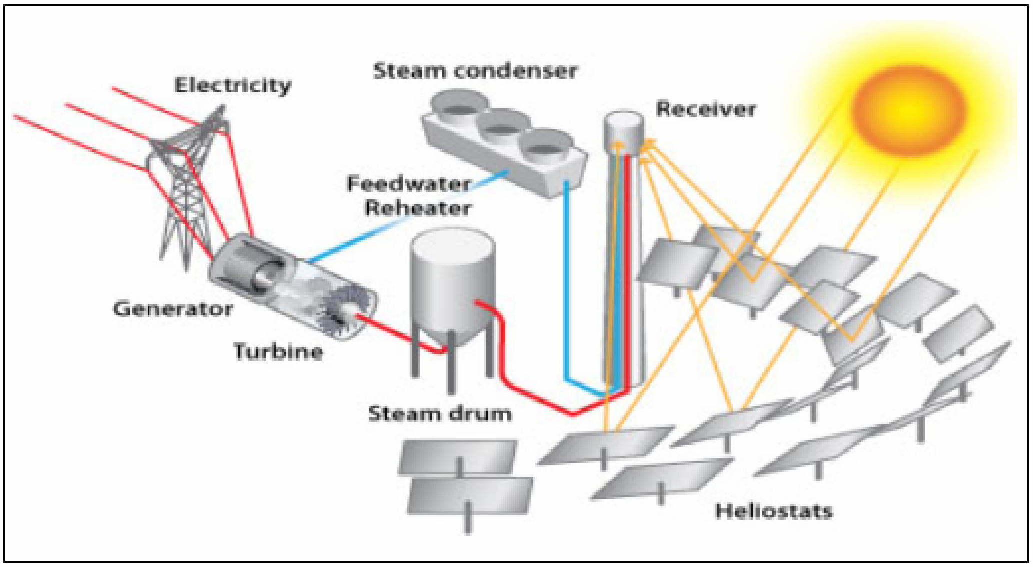
The following are the types of CSP technologies:

- Parabolic trough
- Concentrating linear fresnel reflector
- Stirling dish
- Solar power tower

In all of the above technologies a working fluid is heated by the concentrated sunlight and is then used for power generation and or energy storage.

Figure 12 below is an illustration of the features, characteristics and operation of CSP central receiver/tower power plant. Numerous large, flat, sun-tracking mirrors called heliostats focus sunlight to a receiver at the top of a tower (receiver) and reflect the beam radiation onto a common focal point. A heat-transfer fluid heated in the receiver is used to generate steam, which is then used in a conventional turbine generator to produce electricity. This type of concentrated solar power plant is called molten salt-type, central receiver technology and is based on the concept of thousands of large two axes tracking mirrors known as heliostats.

Figure 12 - Illustration of CSP Central Receiver/Tower Power Plant



Wind

OCGT

CCGT

Imports

APPENDIX B – ENERGY AND DEMAND FORECAST

B.1. CUSTOMER DEMAND

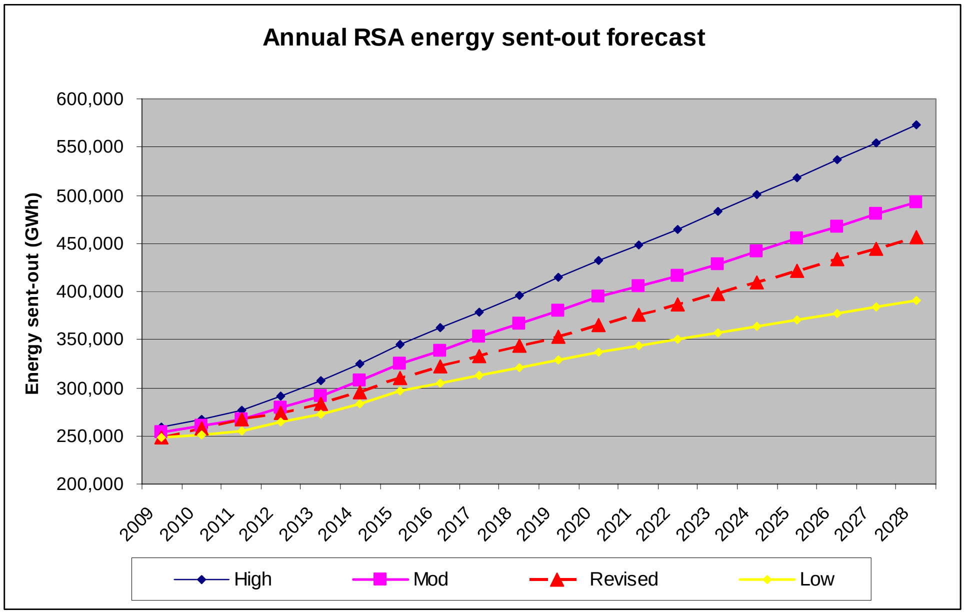
The original long term forecast was finalized in November 2008 as a detailed revision of the previous long-term forecast used in the Integrated System Electricity Plan (Iteration 11, or ISEP11). This November forecast had a greater emphasis on demand reduction as a result of the supply constraints experienced by Eskom. The impact of the Power Conservation Program (PCP) was assumed to be significant as it was expected to be implemented in early 2009.

However the dramatic collapse in financial and commodity markets, as well as the accompanying global (and domestic) economic downturn resulted in a reduction in demand after November 2008. This decline negated the need for the PCP and exceeded the required demand reduction. It also necessitated a revision to the forecast. This revised forecast (derived in June 2009) provides the demand expectation for the IRP.

The revised forecast was based on the historic information available at June 2009. The latest information on future projects and developments was included, as well as the latest expectations and trends. Allowance was made in the shorter term for the global financial crisis. This financial crisis is indeed the most serious since the depression, but due to the cyclical nature of the global economy, it is expected to recover and return to a long term growth trajectory, as illustrated in Figure 13. The challenge is to determine the speed with which this recovery occurs. For this forecast it was assumed that the main impact of the crisis will be felt in 2009, but that South Africa will see growth from 2010 onwards.

The forecast is developed from two mechanisms, one using sector analysis and economic forecasts for each sector, and the other a customer-specific analysis developed in conjunction with customer forecasts of expected demand. The two approaches are reconciled to provide the final forecast.

Figure 13 – Annual sent-out forecast for South Africa



Another difference between the original ISEP12 moderate forecast and the revised moderate is the impact of higher price increases. After the 31% price increase approved by NERSA in 2009 there was a higher likelihood of similar price increases in the medium term with consequent marginal reductions in consumption. These impacts are somewhat muted until substitutes (including self-provision) become more common-place or viable.

Table 12 – Annual energy forecast

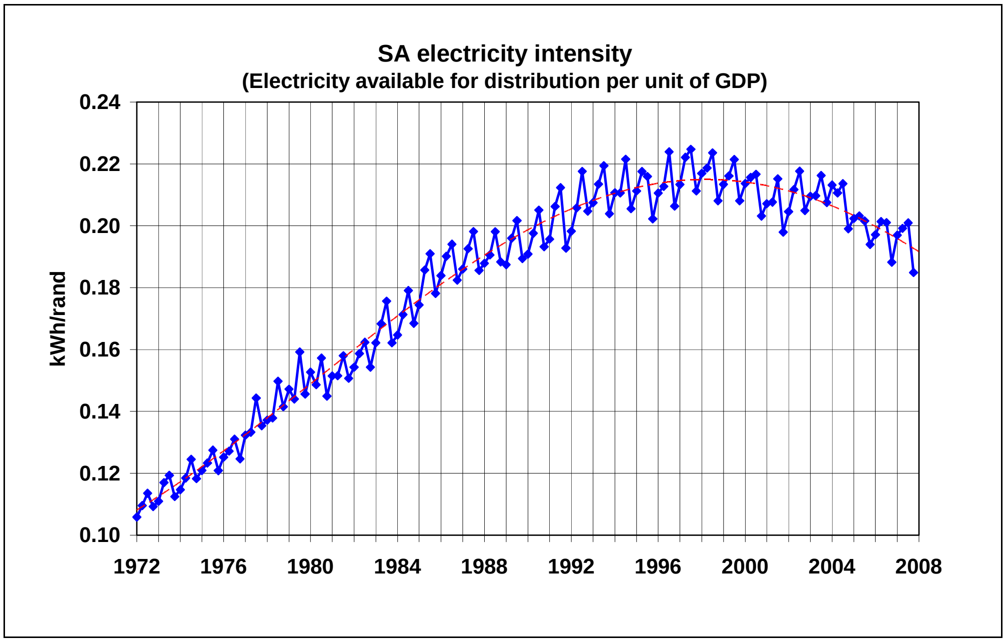
	Annual Energy (GWh)			
	Low	Moderate	Revised	High
2009	248687	253230	248517	259023
2010	251222	259796	258705	266462
2011	255348	266619	267771	276549
2012	264942	278650	276705	291766
2013	273089	291336	288086	306975
2014	283046	306800	301633	324279
2015	296485	325498	318325	345119
2016	304406	338819	331870	362125
2017	312098	353403	344217	378716
2018	320567	365862	356601	395997
2019	329327	380144	368211	414750
2020	337081	394165	380441	431865
2021	343481	405114	390589	448343
2022	350171	416385	401177	464949
2023	357075	428635	412565	482556
2024	363320	441402	424447	500317
2025	370282	454766	436565	518655

2026	376960	467303	448182	536315
2027	383517	480196	459974	554205
2028	390143	492751	471414	572523

In addition the following assumptions underlie the expected demand:

- Known proposed major projects were included;
- A long-term average annual economic growth for South Africa of 4.6% was assumed (in the ISEP12 moderate forecast) for the period up to 2033 resulting in an average annual sales growth of 2.9%. In the revised moderate the growth projection was reduced for the first ten years but with the expectation of returning to a similar growth path after 2018;
- The SA Reserve bank will continue to focus on the control of inflation and as a result the financial environment will be maintained on the same levels as has been the case since 1994, meaning that the current forecasting model will still be applicable;
- A continuation in the decrease of the electricity sales-gdp margin, or a gradual decline in electricity intensity (as indicated in Figure 14);
- Interruptible- and time of use tariffs will not impact energy consumption;
- Moderate winters are assumed; a cold winter can be 0,5% higher and warm winter 0,3% lower than the moderate winter;
- Electrification of homes has been included
- The PCP has not been taken into account.
- The national forecast includes energy consumed by municipal and other customers that are not produced by Eskom generation. This energy consumption will grow at rates applicable to those sectors.
- This forecast includes the large energy-intensive projects scheduled in 2012 and 2013, but excludes further large projects thereafter.

Figure 14 – Trend in electricity intensity in South Africa



The shift in electricity intensity follows the international trend in developing economies as energy-intensive primary extraction and manufacturing sectors are replaced by less energy intensive sectors (such as financial services) as primary drivers of economic growth. Real increases in electricity prices would also have an impact of energy efficiency across all sectors.

The annual energy forecast is converted into a demand forecast for each year by applying an assumed profile for demand over the year to the energy forecast. This provides the annual peak demand (as reflected in the scenario results in Appendix C) as well as the profiles.

Table 13 – Expected annual peak demand

	Annual Peak Demand (MW)			
	Low	Moderate	Revised	High
2009	37503	38188	37845	39061
2010	37818	39109	39432	40112
2011	38528	40229	40914	41727
2012	39988	42057	42373	44037
2013	41299	44059	44238	46424
2014	42987	46594	46511	49249
2015	45108	49522	49164	52507
2016	46313	51549	51269	55095
2017	47692	54004	53411	57872
2018	48906	55816	55259	60413
2019	50423	58203	57265	63502
2020	51617	60358	59145	66131
2021	52678	62130	60787	68760
2022	53801	63974	62518	71436
2023	54933	65941	64346	74237

2024	55874	67882	66153	76942
2025	57010	70018	68091	79854
2026	58093	72015	69942	82650
2027	59152	74064	71816	85479
2028	60047	75840	73432	88117

B.2. DEMAND SIDE MANAGEMENT

There is an expectation of the outcomes of existing (and future) Demand Side Management (DSM) programmes. Table 14 provides the expectation of these outcomes in each of Eskom's financial years until 2019/20.

Table 14 – Expected DSM outcomes

		2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Residential	**MW**	312	15	19	28	36	46	35	35	35	35	35
	GWh	308	53	67	98	126	161	123	123	123	123	123
Commercial	**MW**	7	8	9	89	59	55	50	60	60	60	60
	GWh	19	17.1	47	468	310	289	263	315	315	315	315
Industrial	MW	79	91	62	218	293	228	205	205	205	205	205
	GWh	100	164	380	1337	1797	1398	1257	1257	1257	1257	1257
Redistributor	MW	34	47									
	GWh	1										
Total DSM Projects (MW)	**MW**	**432**	**161**	**90**	**335**	**388**	**329**	**290**	**300**	**300**	**300**	**300**
	GWh	**428**	**234**	**494**	**1903**	**2233**	**1848**	**1643**	**1695**	**1695**	**1695**	**1695**
Cumulative	MW	432	593	683	1018	1406	1735	2025	2325	2625	2925	3225
	GWh	428	662	1156	3058	5291	7140	8782	10477	12172	13867	15562

B.3. POWER CONSERVATION PROGRAMME

For the purposes of the IRP the Power Conservation Programme (PCP), originally proposed by Eskom with continued work undertaken by the National Electricity Response Team (NERT), has been excluded. It is possible that the development of the PCP would continue and that in the medium term this could be implemented, in which case there would be a clear impact on the demand forecast both in the medium term and the longer term. It is conceivable that the PCP would only be fully implemented in the eventuality of a significant increase in demand in excess of that expected in the forecast.

APPENDIX C RESULTS

The optimal plans for the IRP scenarios are shown in the tables below. The capacity required from each project in order to meet the annual peak is shown in each case. It is assumed that in each case the generating unit (in some cases, more than one) would be commercial in the period leading up to the peak.

Table 15 – Reference Case

	Committed	Coal 3	Coal 4	Coal 5	Coal 6	Coal 7	Coal 8	Coal 9	OCGT	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,518
2010	1156	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	0.23	257,997	55,053
2011	1997	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	-	266,631	81,673
2012	1022	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	2.75	273,999	106,840
2013	2127	0	0	0	0	0	0	0	0	2127	50459	42832	17.81	16.32	-	283,226	130,395
2014	2865	0	0	0	0	0	0	0	0	2865	53324	44776	19.09	17.67	-	294,832	152,805
2015	2024	0	0	0	0	0	0	0	0	2024	55348	47139	17.41	16.06	-	309,833	174,295
2016	1381	0	0	0	0	0	0	0	0	1381	56729	48944	15.91	14.60	-	321,696	194,715
2017	723	714	0	0	0	0	0	0	0	1437	58166	50786	14.53	13.28	0.40	332,348	240,689
2018	0	714	0	0	0	0	0	0	0	714	58880	52334	12.51	11.29	3.83	343,036	266,777
2019	0	714	714	0	0	0	0	0	294	1722	60602	54040	12.14	10.96	7.81	352,951	292,189
2020	0	714	714	714	0	0	0	0	0	2142	62744	55920	12.20	11.06	6.70	365,181	341,013
2021	-75	714	714	0	0	0	0	0	0	1353	64097	57562	11.35	10.25	7.00	375,329	370,792
2022	0	714	714	0	0	0	0	0	441	1869	65966	59293	11.25	10.18	8.59	385,917	391,452
2023	-909	0	714	714	714	0	0	0	735	1968	67934	61121	11.15	10.10	7.22	397,305	432,662
2024	-1424	0	714	714	714	714	0	0	441	1873	69807	62928	10.93	9.92	8.09	409,187	469,975
2025	-2740	0	0	714	1428	1428	714	714	0	2258	72065	64866	11.10	10.12	12.51	421,305	519,804
2026	-2280	0	0	714	714	714	1428	714	882	2886	74951	66717	12.34	11.39	7.48	432,922	561,727
2027	0	0	0	714	0	714	714	0	0	2142	77093	68591	12.40	11.47	8.43	444,714	586,138
2028	-2850	0	0	0	714	714	1428	1428	147	1581	78674	70207	12.06	11.15	5.86	456,154	620,618

Table 16 – Domestic emission constraint (Emission 1) Scenario

	Committed	Coal 3	Coal 4	Coal 5	FBC	CSP	Nuclear 1	Nuclear 2	Nuclear 3	CC GT	Tubatse	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,518
2010	1156	0	0	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	0.23	257,997	55,053
2011	1997	0	0	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	-	266,631	82,006
2012	1022	0	0	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	2.20	273,999	107,752
2013	2127	0	0	0	0	0	0	0	0	0	0	2127	50459	42832	17.81	16.32	-	283,226	131,853
2014	2865	0	0	0	0	0	0	0	0	0	0	2865	53324	44776	19.09	17.67	-	294,832	154,766
2015	2024	0	0	0	0	0	0	0	0	0	0	2024	55348	47139	17.41	16.06	-	309,833	176,719
2016	1381	0	0	0	0	0	0	0	0	786	0	2167	57515	48944	17.51	16.21	-	321,696	203,487
2017	723	0	0	0	0	1104	0	0	0	786	0	2613	60128	50786	18.39	16.05	-	332,348	259,232
2018	0	1428	0	0	0	1104	0	0	0	0	0	2532	62660	52334	19.73	16.40	-	343,036	337,518
2019	0	0	0	0	0	1104	0	0	0	0	0	1104	63764	54040	17.99	13.75	-	352,951	380,985
2020	0	714	0	0	0	1104	0	0	0	786	0	2604	66368	55920	18.68	13.60	-	365,181	432,077
2021	-75	714	0	0	0	1104	1650	0	0	0	0	3393	69761	57562	21.19	15.29	-	375,329	513,209
2022	0	0	0	0	0	1104	0	0	0	0	0	1104	70865	59293	19.52	12.86	-	385,917	547,099
2023	-909	0	0	0	0	1104	1650	0	0	0	375	2220	73085	61121	19.57	12.21	-	397,305	613,187
2024	-1424	714	0	0	0	1104	0	1650	0	0	0	2044	75129	62928	19.39	11.36	-	409,187	675,257
2025	-2740	0	0	0	600	1104	0	0	0	0	0	-1036	74093	64866	14.22	5.58	2.43	421,305	707,778
2026	-2280	714	1428	0	0	184	0	1650	0	0	0	1696	75789	66717	13.60	5.06	3.37	432,922	759,668
2027	0	0	714	0	0	0	0	0	1650	0	0	2364	78153	68591	13.94	5.63	5.58	444,714	793,539
2028	-2850	0	714	714	0	0	0	0	1650	0	0	228	78381	70207	11.64	3.53	4.91	456,154	836,914

Table 17 – Regional emission constraint (Emission 2) Scenario

	Committed	Coal 3	Coal 4	Coal 5	FBC	CSP	Nuclear 1	Mmamabula	Moamba	Kudu	CCGT	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,518
2010	1156	0	0	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	0.23	257,997	55,053
2011	1997	0	0	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	-	266,631	82,006
2012	1022	0	0	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	2.20	273,999	107,752
2013	2127	0	0	0	0	0	0	0	0	0	0	2127	50459	42832	17.81	16.32	-	283,226	131,853
2014	2865	0	0	0	0	0	0	0	0	0	0	2865	53324	44776	19.09	17.67	-	294,832	154,766
2015	2024	0	0	0	0	0	0	0	0	0	0	2024	55348	47139	17.41	16.06	-	309,833	176,713
2016	1381	0	0	0	0	0	0	597	0	0	0	1978	57326	48944	17.13	15.82	-	321,696	198,877
2017	723	0	0	0	0	0	0	1194	332	0	0	2249	59575	50786	17.31	16.05	-	332,348	222,886
2018	0	0	0	0	0	0	0	1194	332	0	0	1526	61101	52334	16.75	15.53	-	343,036	248,068
2019	0	0	0	0	0	1012	0	597	0	0	0	1609	62710	54040	16.04	13.93	-	352,951	294,063
2020	0	714	0	0	0	1104	0	0	0	0	0	1818	64528	55920	15.39	12.36	0.51	365,181	358,212
2021	-75	714	0	0	0	1104	0	0	0	0	786	2529	67057	57562	16.50	12.59	-	375,329	408,423
2022	0	0	0	0	0	1104	0	0	0	0	786	1890	68947	59293	16.28	11.56	-	385,917	450,114
2023	-909	714	0	0	0	1104	1650	0	0	0	0	2559	71506	61121	16.99	11.51	-	397,305	521,764
2024	-1424	714	0	0	0	1104	0	0	0	0	786	1180	72686	62928	15.51	9.30	0.70	409,187	560,990
2025	-2740	714	0	0	600	1104	0	0	0	1572	0	1250	73936	64866	13.98	7.11	3.06	421,305	602,197
2026	-2280	714	1428	714	600	1104	0	0	0	0	0	2280	76216	66717	14.24	6.73	3.46	432,922	654,275
2027	0	0	714	714	0	1104	0	0	0	0	0	2532	78748	68591	14.81	6.70	7.15	444,714	681,939
2028	-2850	0	714	714	0	184	1650	0	0	0	0	412	79160	70207	12.75	4.70	4.29	456,154	734,147

Table 18 – Delayed emission constraint (Emission 3) Scenario

	Committed	Coal 3	Coal 4	Coal 5	CSP	Nuclear 1	Nuclear 2	Mmamabula	Moamba	Kudu	Tubatse	CCGT	OCGT	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,518
2010	1156	0	0	0	0	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	0.23	257,997	55,053
2011	1997	0	0	0	0	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	-	266,631	82,006
2012	1022	0	0	0	0	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	2.20	273,999	107,752
2013	2127	0	0	0	0	0	0	0	0	0	0	0	0	2127	50459	42832	17.81	16.32	-	283,226	131,853
2014	2865	0	0	0	0	0	0	0	0	0	0	0	0	2865	53324	44776	19.09	17.67	-	294,832	154,766
2015	2024	0	0	0	0	0	0	0	0	0	0	0	0	2024	55348	47139	17.41	16.06	-	309,833	176,713
2016	1381	0	0	0	0	0	0	0	0	0	0	0	0	1381	56729	48944	15.91	14.60	-	321,696	197,543
2017	723	714	0	0	0	0	0	0	0	0	0	0	0	1437	58166	50786	14.53	13.28	0.29	332,348	243,885
2018	0	714	0	0	0	0	0	0	0	0	0	0	0	714	58880	52334	12.51	11.29	3.16	343,036	270,277
2019	0	714	0	0	0	0	0	0	0	0	375	0	294	1383	60263	54040	11.52	10.34	4.90	352,951	300,465
2020	0	714	0	0	0	0	0	0	0	0	0	1572	0	2286	62549	55920	11.85	10.71	6.77	365,181	332,336
2021	-75	714	1428	0	0	0	0	0	0	0	0	0	0	2067	64616	57562	12.25	11.15	4.94	375,329	370,821
2022	0	714	0	0	0	0	0	0	0	0	0	0	147	861	65477	59293	10.43	9.35	6.23	385,917	391,998
2023	-909	0	0	0	1104	0	0	1194	0	0	0	786	441	2616	68093	61121	11.41	9.46	5.90	397,305	428,224
2024	-1424	0	714	0	1104	0	0	1194	0	0	0	0	0	1588	69681	62928	10.73	7.96	7.74	409,187	465,430
2025	-2740	0	0	0	1104	3300	0	1194	664	2358	0	0	0	5880	75561	64866	16.49	12.95	0.56	421,305	551,688
2026	-2280	0	0	0	1104	0	1650	0	0	0	0	0	0	474	76035	66717	13.97	9.70	4.40	432,922	606,485
2027	0	0	714	714	1104	0	0	0	0	0	0	0	0	2532	78567	68591	14.54	9.59	6.11	444,714	639,814
2028	-2850	0	714	714	1104	0	1650	0	0	0	0	0	0	1332	79899	70207	13.80	8.18	3.15	456,154	697,290

Table 19 – Carbon Tax Scenario

	Committed	Coal 3	Coal 4	Coal 5	Coal 6	Coal 7	Coal 8	Mmamabula	Moamba	Kudu	OCGT	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,597
2010	1156	0	0	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	1.96	257,997	55,281
2011	1997	0	0	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	0.49	266,631	82,306
2012	1022	0	0	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	5.18	273,999	108,237
2013	2127	0	0	0	0	0	0	0	0	0	0	2127	50459	42832	17.81	16.32	0.58	283,226	132,427
2014	2865	0	0	0	0	0	0	0	0	0	0	2865	53324	44776	19.09	17.67	0.26	294,832	155,407
2015	2024	0	0	0	0	0	0	0	0	0	0	2024	55348	47139	17.41	16.06	-	309,833	177,398
2016	1381	0	0	0	0	0	0	0	0	0	0	1381	56729	48944	15.91	14.60	-	321,696	198,257
2017	723	0	0	0	0	0	0	597	332	0	0	1652	58381	50786	14.95	13.70	0.13	332,348	219,878
2018	0	0	0	0	0	0	0	1194	0	0	0	1194	59575	52334	13.84	12.62	2.11	343,036	242,302
2019	0	0	0	0	0	0	0	1194	0	0	0	1194	60769	54040	12.45	11.27	4.62	352,951	265,162
2020	0	0	0	0	0	0	0	597	332	786	0	1715	62484	55920	11.74	10.60	9.78	365,181	289,592
2021	-75	1428	0	0	0	0	0	0	0	0	588	1941	64425	57562	11.92	10.82	6.90	375,329	337,422
2022	0	714	0	0	0	0	0	0	0	0	441	1155	65580	59293	10.60	9.53	8.95	385,917	364,416
2023	-909	714	714	0	0	0	0	0	0	1572	294	2385	67965	61121	11.20	10.15	8.20	397,305	398,104
2024	-1424	714	714	1428	0	0	0	0	0	0	441	1873	69838	62928	10.98	9.97	9.49	409,187	440,744
2025	-2740	714	714	714	1428	714	714	0	0	0	147	2405	72243	64866	11.37	10.39	12.71	421,305	495,533
2026	-2280	0	714	714	714	1428	714	0	0	0	735	2739	74982	66717	12.39	11.43	7.59	432,922	542,955
2027	0	0	714	714	714	0	0	0	0	0	0	2142	77124	68591	12.44	11.51	8.53	444,714	572,462
2028	-2850	0	714	714	714	714	1428	0	0	0	294	1728	78852	70207	12.31	11.41	5.55	456,154	611,670

Table 20 – Risk-adjusted emission portfolio Scenario

	Committed	Coal 3	Coal 4	Coal 5	Nuclear 1	Nuclear 2	CCGT	CSP (Generic)	Kudu	Mmamabula / MSB LP	Moamba	OCGT	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,518
2010	1156	0	0	0	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	1.96	257,997	55,151
2011	1997	0	0	0	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	0.49	266,631	82,131
2012	1022	0	0	0	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	5.18	273,999	108,005
2013	2127	0	0	0	0	0	0	0	0	0	0	0	2127	50459	42832	17.81	16.32	0.58	283,226	132,131
2014	2865	0	0	0	0	0	0	0	0	0	0	0	2865	53324	44776	19.09	17.67	0.26	294,832	155,055
2015	2024	0	0	0	0	0	0	0	0	0	0	0	2024	55348	47139	17.41	16.06	-	309,833	177,002
2016	1381	0	0	0	0	0	0	0	0	0	0	0	1381	56729	48944	15.91	14.60	-	321,696	197,831
2017	723	714	0	0	0	0	0	0	0	0	0	0	1437	58166	50786	14.53	13.28	0.32	332,348	244,372
2018	0	714	0	0	0	0	0	0	0	0	0	0	714	58880	52334	12.51	11.29	5.43	343,036	270,881
2019	0	714	0	0	0	0	0	0	0	0	0	294	1008	59888	54040	10.82	9.64	12.04	352,951	296,659
2020	0	714	0	0	1650	0	0	0	0	0	0	0	2364	62252	55920	11.32	10.18	10.16	365,181	363,931
2021	-75	714	0	0	1650	0	0	184	0	0	0	0	2473	64725	57562	12.44	11.18	5.08	375,329	428,558
2022	0	714	0	0	0	0	0	368	0	0	0	0	1082	65807	59293	10.99	9.45	6.08	385,917	454,993
2023	-909	0	0	0	0	0	786	552	0	1194	0	294	1917	67724	61121	10.80	8.86	8.07	397,305	482,673
2024	-1424	0	0	0	0	0	786	1012	0	1194	0	294	1862	69586	62928	10.58	7.89	9.18	409,187	515,689
2025	-2740	0	0	0	0	0	786	1104	2358	1194	664	0	3366	72952	64866	12.47	9.00	8.13	421,305	551,513
2026	-2280	0	1428	1428	0	0	0	1104	0	0	0	147	1827	74779	66717	12.08	7.89	7.45	432,922	602,695
2027	0	0	714	714	0	1650	0	1104	0	0	0	0	4182	78961	68591	15.12	10.23	6.48	444,714	652,572
2028	-2850	0	714	714	0	0	0	1104	0	0	0	0	-318	78643	70207	12.02	6.46	5.19	456,154	837,550

Table 21 – Increased Option range 1 Scenario

	Committed	Coal 3	Coal 4	Coal 5	Coal 6	Coal 7	Coal 8	Mmamabula	Moamba	MSBL	OCGT	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,518
2010	1156	0	0	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	1.96	257,997	55,151
2011	1997	0	0	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	0.49	266,631	82,131
2012	1022	0	0	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	3.17	273,999	108,897
2013	2127	0	0	0	0	0	0	597	664	0	0	3388	51720	42832	20.75	19.26	-	283,226	136,406
2014	2865	0	0	0	0	0	0	597	0	0	0	3462	55182	44776	23.24	21.82	-	294,832	164,667
2015	2024	0	0	0	0	0	0	0	0	0	0	2024	57206	47139	21.36	20.00	-	309,833	191,460
2016	1381	0	0	0	0	0	0	0	0	600	0	1981	59187	48944	20.93	19.63	-	321,696	218,678
2017	723	0	0	0	0	0	0	0	0	600	0	1323	60510	50786	19.15	17.89	-	332,348	244,619
2018	0	0	0	0	0	0	0	0	0	1200	0	1200	61710	52334	17.92	16.70	-	343,036	270,222
2019	0	714	0	0	0	0	0	0	0	0	0	714	62424	54040	15.51	14.33	0.15	352,951	303,944
2020	0	714	714	0	0	0	0	0	0	0	0	1428	63852	55920	14.18	13.04	2.79	365,181	352,832
2021	-75	714	0	0	0	0	0	0	0	0	0	639	64491	57562	12.04	10.93	6.77	375,329	379,867
2022	0	714	0	0	0	0	0	0	0	0	441	1155	65646	59293	10.71	9.64	8.69	385,917	405,462
2023	-909	714	714	714	0	0	0	0	0	0	1029	2262	67908	61121	11.10	10.06	8.22	397,305	443,774
2024	-1424	714	714	714	714	0	0	0	0	0	441	1873	69781	62928	10.89	9.88	9.51	409,187	483,964
2025	-2740	0	714	714	1428	1428	1428	0	0	0	0	2972	72753	64866	12.16	11.18	9.88	421,305	542,495
2026	-2280	0	714	714	714	714	714	0	0	0	882	2172	74925	66717	12.30	11.35	7.59	432,922	583,234
2027	0	0	714	714	714	0	0	0	0	0	0	2142	77067	68591	12.36	11.43	8.53	444,714	610,922
2028	-2850	0	0	714	714	1428	1428	0	0	0	294	1728	78795	70207	12.23	11.32	5.56	456,154	648,495

Table 22 – Increased Option range 2 Scenario

	Committed	Coal 3	Coal 4	Coal 5	Coal 6	Coal 7	Mmamabula	Moamba	Mpanda Nkua	Kudu	MSBL	MT PPP 2	OCGT	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	0	100	0	872	44257	37413	18.29	18.29	-	248,089	27,822
2010	1156	0	0	0	0	0	0	0	0	0	0	200	0	1356	45613	38839	17.44	16.97	0.68	257,997	56,186
2011	1997	0	0	0	0	0	0	0	0	0	0	200	0	2197	47810	40231	18.84	17.73	0.04	266,631	84,334
2012	1022	0	0	0	0	0	0	0	0	0	0	300	0	1322	49132	41355	18.81	17.26	0.22	273,999	112,691
2013	2127	0	0	0	0	0	597	664	0	0	0	100	0	3488	52620	42832	22.85	21.36	-	283,226	142,014
2014	2865	0	0	0	0	0	597	0	0	0	0	0	0	3462	56082	44776	25.25	23.83	-	294,832	171,969
2015	2024	0	0	0	0	0	0	0	0	0	0	0	0	2024	58106	47139	23.27	21.91	-	309,833	200,294
2016	1381	0	0	0	0	0	0	0	0	1572	600	0	0	3553	61659	48944	25.98	24.68	-	321,696	242,323
2017	723	0	0	0	0	0	0	0	777	786	600	0	0	2886	64545	50786	27.09	25.53	-	332,348	272,935
2018	0	0	0	0	0	0	0	0	259	0	1200	0	0	1459	66004	52334	26.12	24.51	-	343,036	303,365
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	66004	54040	22.14	20.58	-	352,951	331,766
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	66004	55920	18.03	16.52	-	365,181	357,944
2021	-75	714	0	0	0	0	0	0	0	0	0	0	0	639	66643	57562	15.78	14.31	0.30	375,329	400,137
2022	0	714	0	0	0	0	0	0	0	0	0	0	0	714	67357	59293	13.60	12.18	1.72	385,917	427,725
2023	-909	714	714	0	0	0	0	0	0	0	0	0	1029	1548	68905	61121	12.74	11.35	4.21	397,305	461,820
2024	-1424	714	714	1428	0	0	0	0	0	0	0	0	0	1432	70337	62928	11.77	10.43	6.54	409,187	503,517
2025	-2740	714	714	714	1428	1428	0	0	0	0	0	0	0	2258	72595	64866	11.92	10.61	10.77	421,305	557,695
2026	-2280	714	714	714	714	714	0	0	0	0	0	0	1029	2319	74914	66717	12.29	11.02	7.70	432,922	599,383
2027	0	0	714	714	714	714	0	0	0	0	0	0	0	2856	77770	68591	13.38	12.15	6.66	444,714	632,856
2028	-2850	0	714	714	1428	714	0	0	0	0	0	0	294	1014	78784	70207	12.22	11.01	5.67	456,154	668,219

Table 23 – Low CO_2 Investment Scenario

	Committed	Nuclear 1	Nuclear Fleet	CSP	Wind	Hydro	Moamba	Mpanda Nkua	Kudu	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	772	44157	37413	18.03	18.03	-	248,089	27,518
2010	1156	0	0	0	0	0	0	0	0	1156	45313	38839	16.67	16.20	0.23	257,997	55,053
2011	1997	0	0	0	0	0	0	0	0	1997	47310	40231	17.60	16.48	-	266,631	82,006
2012	1022	0	0	0	0	0	0	0	0	1022	48332	41355	16.87	15.33	1.10	273,999	108,680
2013	2127	0	0	184	400	50	664	0	0	3425	51757	42832	20.84	18.19	-	283,226	136,932
2014	2865	0	0	92	0	0	0	0	0	2957	54714	44776	22.19	19.56	-	294,832	164,283
2015	2024	0	0	276	0	0	0	0	0	2300	57014	47139	20.95	18.15	-	309,833	192,021
2016	1381	0	0	552	400	50	0	0	1572	3955	60969	48944	24.57	20.48	-	321,696	235,095
2017	723	0	0	552	0	0	0	777	786	2838	63807	50786	25.64	20.85	-	332,348	268,953
2018	0	0	0	552	0	0	0	259	0	811	64618	52334	23.47	18.20	-	343,036	303,327
2019	0	0	0	552	400	0	0	0	0	952	65570	54040	21.34	15.02	-	352,951	337,549
2020	0	1650	0	552	0	50	0	0	0	2252	67822	55920	21.28	14.64	-	365,181	414,684
2021	-75	0	0	552	0	0	0	0	0	477	68299	57562	18.65	11.72	-	375,329	448,076
2022	0	1650	0	552	400	0	0	0	0	2602	70901	59293	19.58	11.74	-	385,917	516,342
2023	-909	0	1650	552	0	50	0	0	0	1343	72244	61121	18.20	10.10	-	397,305	580,554
2024	-1424	0	1650	552	0	0	0	0	0	778	73022	62928	16.04	7.74	1.21	409,187	640,928
2025	-2740	0	3300	552	0	0	0	0	0	1112	74134	64866	14.29	5.81	5.69	421,305	724,279
2026	-2280	0	3300	552	400	50	0	0	0	2022	76156	66717	14.15	4.88	6.22	432,922	802,483
2027	0	0	0	552	0	0	0	0	0	552	76708	68591	11.83	2.42	11.80	444,714	832,314
2028	-2850	0	3300	552	0	0	0	0	0	1002	77710	70207	10.69	1.10	150.60	456,154	901,964

Table 24 – Policy Investment Scenario

	Committed	Nuclear 1	Nuclear Fleet	CSP	Wind	Hydro	Mmamabula	Moamba	Mpanda Nkua	Kudu	MT PPP 2	MSBL	DoE OCGT IPP	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm
2009	772	0	0	0	0	0	0	0	0	0	100	0	0	872	44257	37413	18.29	18.29	-	248,089	27,822
2010	1156	0	0	0	0	0	0	0	0	0	200	0	0	1356	45613	38839	17.44	16.97	-	257,997	56,145
2011	1997	0	0	0	0	0	0	0	0	0	200	0	0	2197	47810	40231	18.84	17.73	-	266,631	84,290
2012	1022	0	0	0	0	0	0	0	0	0	300	0	0	1322	49132	41355	18.81	17.26	-	273,999	112,637
2013	2127	0	0	184	400	50	0	664	0	0	100	0	1020	4545	53677	42832	25.32	22.67	-	283,226	142,747
2014	2865	0	0	92	0	0	597	0	0	0	0	0	1020	4574	58251	44776	30.09	27.46	-	294,832	174,259
2015	2024	0	0	0	0	0	597	0	0	0	0	0	0	2621	60872	47139	29.13	26.63	-	309,833	204,888
2016	1381	0	0	276	200	30	0	0	0	1572	0	600	0	4059	64931	48944	32.66	29.55	-	321,696	249,277
2017	723	0	0	0	0	0	0	0	777	786	0	600	0	2886	67817	50786	33.53	30.23	-	332,348	281,549
2018	0	0	0	552	0	0	0	0	259	0	0	1200	0	2011	69828	52334	33.43	29.59	-	343,036	314,845
2019	0	0	0	0	100	0	0	0	0	0	0	0	0	100	69928	54040	29.40	25.54	-	352,951	345,493
2020	0	0	0	552	0	30	0	0	0	0	0	0	0	582	70510	55920	26.09	21.81	-	365,181	375,839
2021	-75	0	0	0	0	0	0	0	0	0	0	0	0	-75	70435	57562	22.36	18.21	-	375,329	403,656
2022	0	0	0	552	100	0	0	0	0	0	0	0	0	652	71087	59293	19.89	15.23	-	385,917	431,012
2023	-909	1650	0	0	0	0	0	0	0	0	0	0	0	741	71828	61121	17.52	13.00	-	397,305	488,618
2024	-1424	1650	0	552	0	0	0	0	0	0	0	0	0	778	72606	62928	15.38	10.55	0.83	409,187	543,325
2025	-2740	0	3300	0	0	0	0	0	0	0	0	0	0	560	73166	64866	12.80	8.11	6.67	421,305	621,418
2026	-2280	0	3300	552	100	0	0	0	0	0	0	0	0	1672	74838	66717	12.17	7.06	59.88	432,922	695,544
2027	0	0	1650	0	0	0	0	0	0	0	0	0	0	1650	76488	68591	11.51	6.54	11.33	444,714	741,414
2028	-2850	0	3300	552	0	0	0	0	0	0	0	0	0	1002	77490	70207	10.37	5.12	138.84	456,154	806,051

APPENDIX D CRITERIA

Criteria for evaluating plans

Area	Criteria Name	Metric	Direction	Weighting
Environmental	Absolute CO_2 emissions	Average annual domestic CO_2 emissions (2009-2028)	Minimise	0.28
Financial	Cost of plan	Total PV cost of plan (2009-2028), normalised to reference	Minimise	0.40
Policy	Installed coal-fired capacity	% of total energy generated from PF coal-fired options in 2028	Minimise	0.12
Security of supply	Risk factor	Weighted average of project risk factors (by capacity contribution)	Minimise	0.20

Measuring the criteria

Metrics

The risk factors

Risk rating			
Projects	R	Rationale	Scoring
No risk project	0	High confidence in cost assumptions High confidence in technology High confidence in timing High confidence in reliability Minimal safety concerns No resource concerns	
PF Coal	3	High confidence in cost assumptions High confidence in technology High confidence in reliability Moderate confidence in timing Minimal safety concerns Moderate resource concerns: water, sorbent	 +1 +2
OCGT	4	Moderate confidence in cost assumptions High confidence in technology High confidence in timing High confidence in reliability Minimal safety concerns High resource concerns: diesel	+1 +3
FBC	5	Low confidence in cost assumptions Moderate confidence in technology Moderate confidence in timing High confidence in reliability Minimal safety concerns	+2 +1 +1

		Low resource concerns: water	+1
CSP	10	Poor confidence in cost assumptions Low confidence in technology Low confidence in timing Moderate confidence in reliability Minimal safety concerns Moderate resource concerns: water	+3 +2 +2 +1 +2
Wind	4	Moderate confidence in cost assumptions High confidence in technology High confidence in timing Poor confidence in reliability Minimal safety concerns No resource concerns	+1 +3
Small hydro	4	Moderate confidence in cost assumptions High confidence in technology Moderate confidence in timing Low confidence in reliability Minimal safety concerns No resource concerns	+1 +1 +2
Nuclear	5	Moderate confidence in cost assumptions Moderate confidence in technology Moderate confidence in timing High confidence in reliability Moderate safety concerns (waste disposal) No resource concerns	+1 +1 +1 +2
CCGT	7	Low confidence in cost assumptions High confidence in technology Moderate confidence in timing High confidence in reliability Low safety concerns (port traffic) High resource concerns: LNG	+2 +1 +1 +3
PS	2	Moderate confidence in cost assumptions High confidence in technology Moderate confidence in timing High confidence in reliability Minimal safety concerns No resource concerns	+1 +1
Mmamabula	3	High confidence in cost assumptions High confidence in technology Moderate confidence in timing High confidence in reliability Minimal safety concerns Moderate resource concerns: water	 +1 +2
Moamba	3	Moderate confidence in cost assumptions High confidence in technology Moderate confidence in timing High confidence in reliability Minimal safety concerns No resource concerns	+1 +2
Kudu	9	Poor confidence in cost assumptions High confidence in technology Poor confidence in timing	+3 +3

		Moderate confidence in reliability Minimal safety concerns Moderate resource concerns: natural gas	+1 +2
MSBLP	8	Poor confidence in cost assumptions High confidence in technology Poor confidence in timing High confidence in reliability Minimal safety concerns Moderate resource concerns: water	+3 +3 +2
Mpanda Nkua	6	Poor confidence in cost assumptions High confidence in technology Poor confidence in timing High confidence in reliability Minimal safety concerns No resource concerns	+3 +3
DOE OCGT	5	Moderate confidence in cost assumptions High confidence in technology Moderate confidence in timing High confidence in reliability Minimal safety concerns High resource concerns: diesel	+1 +1 +3
MTPPP2	3	High confidence in cost assumptions High confidence in technology Moderate confidence in timing Low confidence in reliability Minimal safety concerns No resource concerns	 +1 +2

Weighting the risk factors for each scenario

Risk rating				
Plan	R	Projects	New Capacity	Scoring
Reference	3.1	PF Coal	28560	3
		OCGT	2940	4
Domestic emissions	6.2	PF Coal	7854	3
		FBC	600	5
		CSP	10120	10
		Nuclear	9900	5
		CCGT	2358	7
		PS	375	2
Regional emissions	6.1	PF Coal	9282	3
		FBC	1200	5
		CSP	10028	10
		Nuclear	3300	5
		CCGT	2358	7
		Mmamabula	3582	3
		Moamba	664	3
		Kudu	1572	9
Delayed emissions	5.5	PF Coal	9996	3
		OCGT	1176	4
		CSP	6532	10
		Nuclear	4950	5
		CCGT	2358	7

		Mmamabula	3582	3
		Moamba	664	3
		Kudu	2358	9
MYPD Capacity	5.5	PF Coal	9996	3
		OCGT	1029	4
		CSP	6532	10
		Nuclear	4950	5
		CCGT	2358	7
		Mmamabula	3582	3
		Moamba	664	3
		Kudu	2358	9
Carbon Tax	3.5	PF Coal	22134	3
		OCGT	2940	4
		Mmamabula	3582	3
		Moamba	664	3
		Kudu	2358	9
IPP Alternate 1	3.5	PF Coal	24276	3
		OCGT	3087	4
		Mmamabula	1194	3
		Moamba	664	3
		MSBL	2400	8
IPP Alternate 2	4.0	PF Coal	20706	3
		OCGT	2352	4
		Mmamabula	1194	3
		Moamba	664	3
		Mpanda Nkua	1036	6
		Kudu	2358	9
		MTPPP2	900	3
		MSBL	2400	8
Low CO2	6.5	Nuclear	16500	5
		CSP	7728	10
		Wind	2000	4
		Hydro	250	4
		Mpanda Nkua	1036	6
		Moamba	664	3
		Kudu	2358	9
Policy	6.0	Nuclear	14850	5
		CSP	3864	10
		Wind	900	4
		Hydro	110	4
		Mmamabula	1194	3
		Mpanda Nkua	1036	6
		Moamba	664	3
		MTPPP2	900	3
		MSBL	2400	8
		DoE OCGT	2040	5
		Kudu	2358	9

Some of the criteria proposed by the Sustainability Working Group were excluded. These are listed below with the reasons for exclusion. Most of these excluded criteria will provided indicators (as used in the main part of the report) to provide information that would not necessary form part of the MCDM process to select the preferred plan.

Area	Criteria Name	Metric	Reason for exclusion
Policy	Net import limit	% of total installed capacity from import options	This is an Eskom board directive – not appropriate for a national IRP. In addition the diversity agenda is supported by the criteria on coal-based production. This will be used as an indicator to identify any additional risk from increased imports.
Environmental	Relative CO_2 Emissions	CO_2 emissions per MWh in 2025	It was decided that there was a preference to use an absolute target as the indicator. The relative emissions would potentially continue as an indicator.
Policy	Renewable energy generation	Total energy sent-out by renewable sources in 2013 (GWh)	This should be a “hard” requirement which each plan has to meet (not only a criterion). For each plan we need to calculate the value and indicate that the plan does meet this.
Environmental	Availability of clean technology funds and credits	?	It was decided that this was not critical at this stage. The impact would be on project financing.
Environmental	Waste impact	?	Need to look at a more complex approach to deal with different types of waste and the impact of each.
Security of supply	Local resource constraints	?	This needs to be discussed further – possibly for the next round of the IRP with discussion on how costs at different sites would reflect relative scarcities of resources and the costs of importing them (esp. water, sorbent). Could look at minimising the usage of the total resource or be location specific.
Policy	GDP multiplier	Total GDP multiplier implied by new build options (Rb)	Additional research is required to provide indicators of multipliers for additional projects (and how these relate to existing data).
Environmental	Land usage	Hectares of alternate use land taken up by the plan	Paucity of data to make meaningful deductions, especially as regional issues need to be assessed

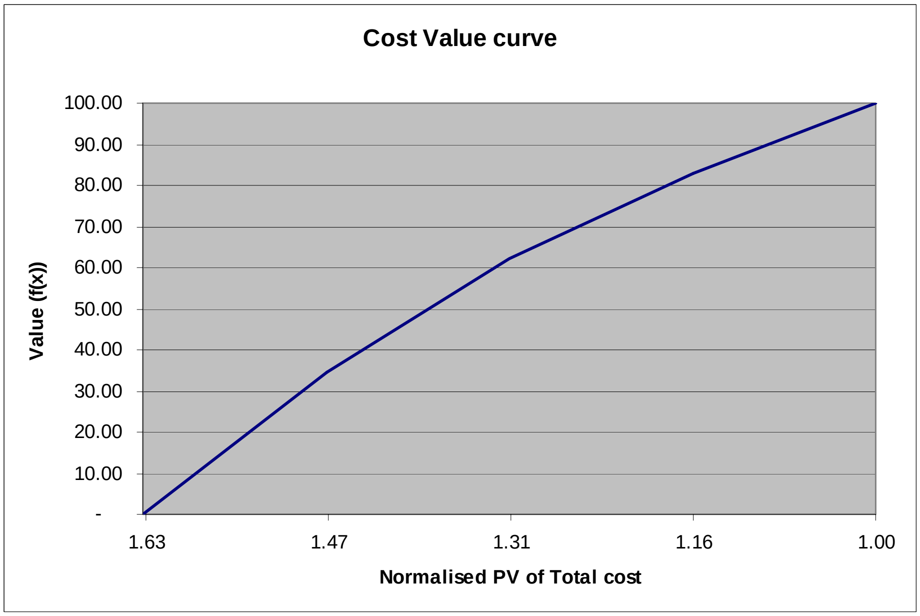
Policy	Flexibility	Total costs committed upfront as a proportion of total costs of plan (?)	Need to appropriately define the upfront commitments, especially including coal contracts, etc. Additional work is needed to identify the metric and define it appropriately.
Security of supply	Unserved energy	Total unserved energy over the planning horizon (GWh)	This Is already catered for in the Cost of Unserved Energy reflected in the PV cost of each plan. Should be reported as an indicator, but not a criterion.

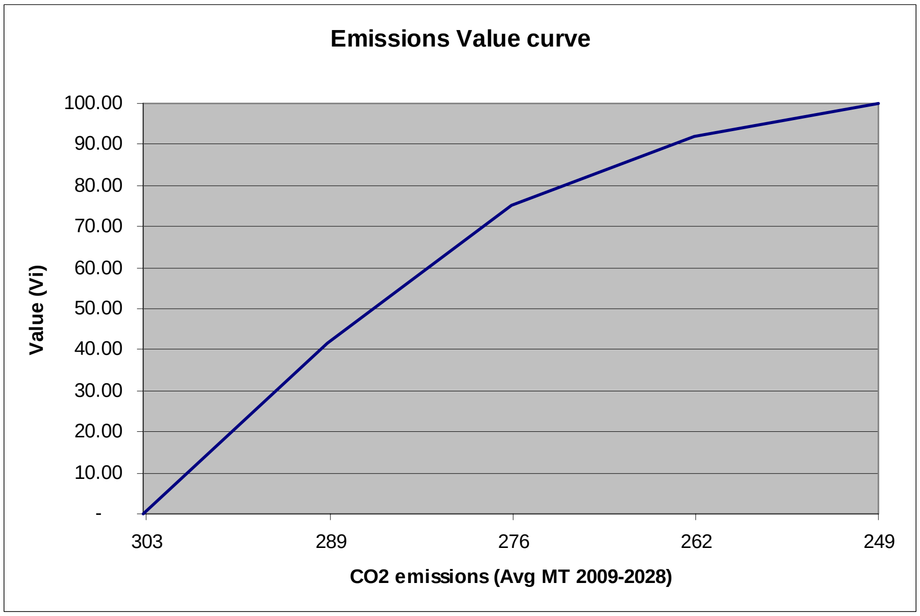
APPENDIX E PARTIAL VALUE FUNCTIONS

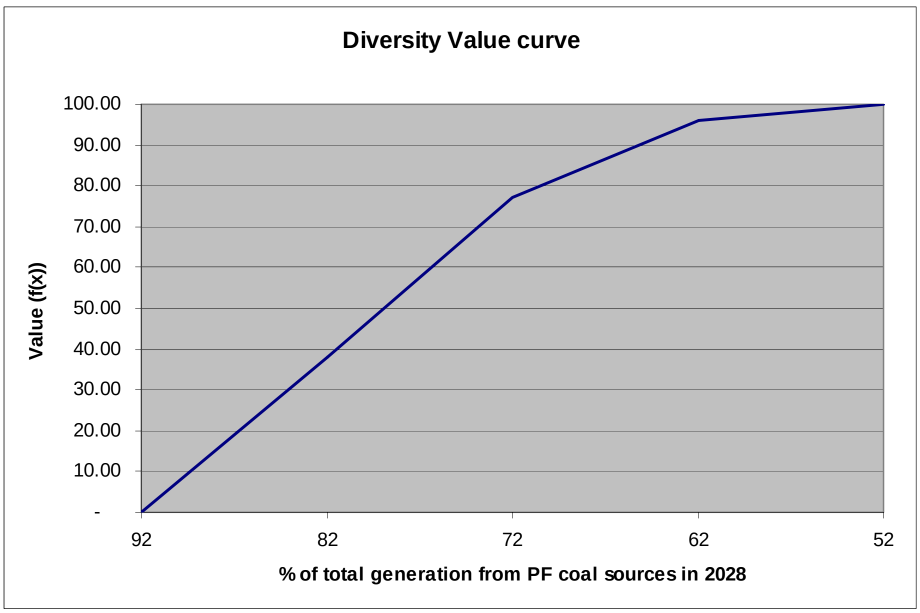
Purpose of the partial value functions

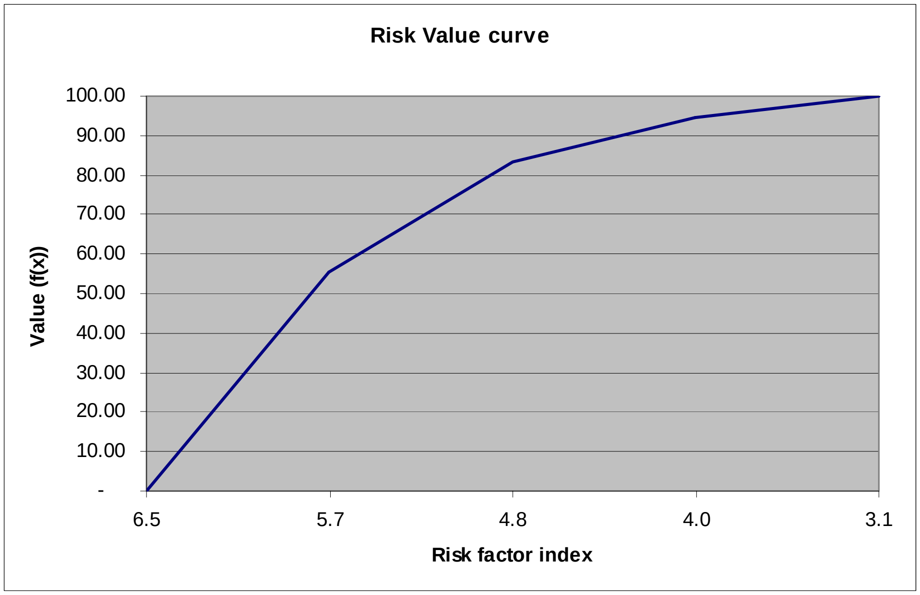
Methodology for calculating partial value functions

Results




Emissions Value curve
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Value (Vi)
303
289
276
262
249
CO2 emissions (Avg MT 2009-2028)


Diversity Value curve
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Value (f(x))
92
82
72
62
52
% of total generation from PF coal sources in 2028


Risk Value curve
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Value (f(x))
6.5
5.7
4.8
4.0
3.1
Risk factor index