NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

MULTI – YEAR PRICE DETERMINATION (MYPD)

METHODOLOGY

Contents

1. Executive Summary

In terms of Section 4 of the National Energy Regulator Act, 2004 (Act No.40 of 2004), NERSA's mandate is to regulate the electricity industry in terms of the Electricity Regulation Act, 2006 (Act No. 4 of 2006), regulate the piped-gas industry in terms of the Gas Act, 2001 (Act No. 48 of 2001), and regulate the petroleum pipelines industry in terms of the Petroleum Pipelines Act, 2003 (Act No. 60 of 2003). The Energy Regulator determines Eskom allowed revenue on a multi-year basis.

The Energy Regulator implemented the first Multi Year Price Determination (MYPD) for Eskom business activities namely, generation, transmission and distribution from 1 April 2006 to 31 March 2009. Eskom applied twice in 2007 for re-opening the MYPD. The Energy Regulator approved changes to the MYPD rules in July 2008. The purpose of this document is to consolidate and align the regulatory methodology into one document from various pieces which were approved by the Energy Regulator from various submissions. This methodology will be used to evaluate Eskom's applications for revenue requirements.

2. Introduction and Background

The Multi Year Price Determination (MYPD) incorporates some of the Rate of Return (RoR) and incentive based principles through the introduction of the transmission and distribution service incentive schemes and the energy efficiency demand side management (EEDSM) schemes. The RoR methodology states that "the revenue to be earned by Eskom should be equal to the efficient cost to supply electricity plus a fair return on the rate base". This methodology was the subject of separate consultations which NERSA had with the stakeholders since the first MYPD in 2006. The MYPD2 will apply during a crucial period of the implementation of Eskom's expansion program and therefore there is a need to ensure a stable regulatory approach.

NERSA begun developing a regulatory methodology in 2003, viz, the rate of return methodology, which sets the average prices separately for each of Eskom's three business activities.

3. Objectives to be achieved by the MYPD mechanism

Regulatory methodologies that will enable a three-year price determination need to be tested against a set of regulatory objectives. The objectives guide the development of a regulatory methodology underlying the MYPD. The following objectives are adopted in developing the regulatory methodology for the MYPD:

- To ensure Eskom’s sustainability as a business and limit the risk of excess or inadequate returns; while giving incentives for new investment, especially in generation;
- To ensure reasonable tariff stability and smoothed changes over time consistent with the socio-economic objective of the Government;
- To appropriately allocate commercial risk between Eskom and its customers;
- To provide efficiency incentives without leading to unintended consequences of regulation on performance;
- To provide a systematic basis for revenue/tariff setting;
- To ensure consistency between price control periods;

4. Regulatory methodology for Eskom’s three business Activities (i.e. Generation, Transmission and Distribution)

Section 15 (1) of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) (“the Act”) states that a licence condition relating to approval of tariffs must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return and also provide for or prescribe incentives for continued improvement of technical and economic efficiency with which services are to be provided.

In order to exercise this mandate, NERSA has developed a regulatory methodology which consists of the principles of rate of return as well as incentives for efficient performance. The methodology ensures that each of Eskom’s businesses is given efficient expenditure, compensated for the cost of providing services to the customers. The methodology consists of the allowed revenue requirement formulas for generation, transmission and distribution. These formulas are used to calculate the allowed revenue in each of these business units.
The regulatory formulas are expressed as follows:

4.1 The Generation Formula

Generation formula is as follows:

Allowed Revenues
=
Return on RAB and working capital
+
Generation opex
+
Generation depreciation
+
Efficient primary energy costs (inclusive of non Eskom generation)
+
Transmission charges pass-through (regulated separately)
+/-
Risk management adjustments[1]

4.2 Transmission Formula

Transmission formula is as follows:

Allowed Revenues
=
Return on RAB and working capital
+
Transmission opex costs
+
Transmission depreciation
+
Transmission charges (network costs, losses & ancillary charges)
+
Allowances for service incentives
+/-
Risk management adjustments

[1] These risk management adjustments are described under section 6 of this document. The risk of excess or inadequate returns is managed by: Management of inadequate or excess returns through risk adjustments of primary energy, capital expenditure, Eskom non generation, CPI as well as sales volume variances. Provision is also made to claw back over recovery and return under recovery of allowed revenue.

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4.3 The Distribution Formula

Distribution formula is as follows:

Allowed Revenues
=
Return on RAB and working capital
+
Distribution opex
+
Distribution depreciation
+
Allowances for Service incentives
+
Allowance for Demand side management and energy efficiency
+
Transmission revenues pass-through (regulated separately)
+
Generation revenues pass-through (regulated separately)
+/-
Risk management adjustments

A description of each of the items in the regulatory methodology is outlined below:

5. The Components of the Allowed Revenues

Allowed revenues in each formula mainly consists of the return on allowed asset base and a return of depreciation of assets, operating costs and other costs regulated elsewhere in the value chain. The regulatory formulas for generation, transmission and distribution are as follows.

Rate of return

The real rate of return shall be calculated using the Weighted Average Cost of Capital (WACC). The WACC is an estimate of the investors' required rate of return for a given risk level associated with an investment made in Eskom.

5.1 Cost of Debt

5.1.1. The cost of debt (K_d) is the actual contracted cost of debt for the Eskom;
5.1.2. The cost of debt is based on weighted average costs of debt for Eskom's regulated business under review;
5.1.3. Where Eskom raises corporate debt, then the actual cost of debt charge to the regulated activity must fairly reflect the risks of each regulated activity;
5.1.4. These returns should be adjusted from nominal to real using the consumer price index.

Formula for calculating cost of debt is as follows:
K_d Real = {(1+ (K_d *(1-t)}/ (1+CPI)} -1

Where:
K_d = the cost of debt nominal pre-tax
t = Corporate tax rate for the MYPD period
CPI = is the forecast consumer price index for the MYPD period

5.2 Cost of equity

5.2.1 The cost of equity (K_e) is determined using the Capital Asset Pricing Model (CAPM)
5.2.2 The formula for the (K_e) = Risk free rate (R_f) + (expected market risk premium (M_{rp})* beta(β))
The formula is as follows:

K_e Real = R_f + (M_{rp}* β)

Where:
K_e = Nominal cost of equity
R_f = risk free rate
M_{rp} = market risk premium
β = beta

Formula for calculating cost of equity is as follows:
K_e = {1+ (K_e *(1-t)}/ {1+CPI} -1

5.2.3 Risk free rate is determined using spot prices of selected 10 year maturity South African Government bonds;
5.2.4 The MRP is calculated using historical average return of the JSE All Share Index(ALSI) adjusted for resources bias i.e. JSE financial and industrial index using a 25 year historical average;

Beta

5.2.5 Eskom's equity beta is benchmarked in the same range as international utilities operating under comparable business risk

5.2.6 The beta will be established using a selected list of 6 comparators (proxy) of similar utilities listed in a stock. These are proxy companies facing similar regulatory and business risks.

5.2.7 Using 6 proxy companies, the value of the beta is determined using the following steps:

- For each proxy company its equity beta is obtained from a published independent source;
- Estimate the asset beta (βa) for each proxy by de-gearing each proxy equity beta by using the following
- Estimate the asset beta, βa, for each Proxy Company or sector by de-gearing the comparator's equity beta by using the following formula:

$$\beta_a = \beta_{e,comparator} \times (1 - g_{comparator})$$

Where:

βa = unlevered asset beta of a proxy
βe = equity beta of a proxy
g=the gearing of a proxy

For each value of the asset beta, the adjusted proxy equity beta (βe) is estimated using the gearing of the Company or industry subject to the price review:

$$\beta_e = \beta_a / (1 - g)$$

Where:

βa = unlevered asset beta of a proxy
βe = equity beta of a proxy
g=the gearing of the company (Eskom)

The mean of this set of equity beta values is taken. This is the beta to be used (Note: This beta may also, where applicable be adjusted for company size and construction or Greenfield project).

5.2.8 The Energy Regulator will use actual gearing submitted by the Eskom after assessing its appropriateness.

Weighted Average Cost of Capital (WACC)

5.2.9 The Real pre-tax WACC is as follows:

Cost of capital	**Base**
Cost of Debt (K_d)	
Actual contracted cost of debt (Real)	xxxx
Cost of Equity	
Pre-tax cost of equity (K*e*)	xxxx
Pre tax wacc **(Kd x G) + (Ke x 1-G)** **where G is the gearing**	**xxxx**

5.3 Regulatory Asset Base (RAB)

Rules for the RAB

The RAB covers all assets employed by Eskom in the production and supply of electricity. The following are the conditions that must be met in order to include an asset in the RAB.

5.3.1 Fixed assets must be long-term in nature and must be used and useable;
5.3.2 Fixed and other assets that are not in a used and useable form will not be included in the RAB;
5.3.3 Used and useable means that assets should be in a condition that makes it possible to supply demand in the short-term (within12 months);
5.3.4 The working capital will be include in the RAB for the purposes of calculating the return;
5.3.5 The return on capital will be based on the replacement value of the assets;
5.3.6 The historic asset base as at 31 March 2006 will be used as an opening asset base (This asset base will be used as a basis to determine the replacement value of Eskom's assets);
5.3.7 The revaluation reserve will no earn a return on capital. The revaluation adjustments are explained in depreciation below;
5.3.8 Customer funded assets and prepayments will be deducted from the regulatory asset base;
5.3.9 The mothballed and/or impaired assets will not earn a return although the maintenance of mothballed assets with a definite plan for future use, will be allowed in the operating expenses

Capital work under construction (WUC)

5.3.10 The exception to rule 5.3.2, however, is with regard to work under construction, which will be capitalized as and when construction costs are incurred;

5.3.11 Interest during Construction (IDC) will not be capitalized or allowed a return.

Valuation Basis

The policy position 1 of the Electricity Pricing Policy (EPP) states that:

a. The revenue requirement for a regulated licensee must be set at a level which recovers the full cost of production, including a reasonable risk adjusted margin or return on appropriate asset values. The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that accurately reflects the replacement value of assets of those assets such as to allow the electricity utility to obtain reasonably priced funding for investment: to meet Government defined economic growth.

b. In addition, the regulatory methodology should anticipate investment cycles and other trends to prevent unreasonable price volatility and shocks while ensuring financial, viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator.

5.3.12 The assets will be valued on the replacement costs basis;

5.3.13 Because replacement cost is subjective, the Energy Regulator requires that replacement costs be established on the basis of "like for like replacement value", this means that the assets are revalued on the basis of replacing the existing assets;

5.3.14 This does not allow the use of modern equivalent asset value (MEAV)[2], where the forecast is on valuing the cost of assets needed to provide the equivalent service being provided by the existing assets;

5.3.15 Since the replacement costs valuation exercise tend to be expensive and time consuming, the Energy Regulator will approve the use of consumer price indexed replacement values between valuation periods. Replacement cost should be determined as in 5.3.13 above.

[2] The Energy Regulator's preferred replacement valuation basis that removes subjectivity, achieves consistency and ensures the "like for like" valuation is the inflation-indexed cost

Valuation reserve

5.3.16 The valuation reserve does not represent an investment towards cost of service; rather it's an adjustment to bring the asset values to the current replacement costs;

5.3.17 This revaluation reserves will therefore not be included in determining the capital structure for the purposes of calculating the WACC. The revalued asset will be allowed to earn a rate of return while revaluation reserve is amortised annually;

5.3.18 However, as an exception the amortised amount will not be included in the return of investment and will also not form part of the regulatory expenses (and consequently will be excluded from the revenue requirement)

Accumulated Depreciation

5.3.19 Accumulated depreciation is the cumulative straight line depreciation of regulated property, plant and equipment;

5.3.20 The depreciation should be calculated on historical cost of an asset and this is separate from the amortization of the revaluation amount;

5.3.21 The total accumulated depreciation and accumulated amortisation is deducted from the replacement cost valued regulatory asset base to obtain the regulatory asset base on which to calculate the return.

5.4 Allowable Operating expenses

Allowable operating expenses relates to all expenses that are incurred in the production and supply of electricity. These costs include normal operating expenditures, maintenance costs, manpower costs, and overheads (centrally administered charges). Normally these costs are recovered within 1 year.

The qualifying criteria for these expenses are as follows:

5.4.1 Expenses must be incurred in the normal operations of production and supply of electricity, including an acceptable level of refurbishment, repairs and maintenance costs;

5.4.2 Expenses must be prudently and efficiently incurred after careful consideration of available options;

5.4.3 Expenses must be incurred in an arm's length transaction. Eskom must have a competitive procurement policy and demonstrate to the regulator that it has been strictly adhered to in its procurement processes;

5.4.4 For any exogenous factors, expenses incurred under extraordinary circumstances consideration shall be given to spreading such expenses over a number of years;
5.4.5 Only the efficient human resources will be allowed;
5.4.6 Corporate social investment and expenses on charitable donations and broad social development activities however they cannot be included as qualifying (regulated) expenses and would need to be funded from below the bottom-line or by the shareholder;
5.4.7 Expenses on advertising not related to the core business of supplying electricity will also be disallowed;
5.4.8 Costs of special characters that are allowable in the revenues include primary energy, research and development costs for regulated activities, transmission service quality incentives, transmission supply quality incentives or system minutes, distribution service incentives and Energy Efficiency and Demand Side Management (EEDSM). These costs are discussed as in paragraphs that follows below:

5.5 Primary Energy

Primary energy costs are all efficiently incurred costs in the purchase of primary energy resources. They include the fuel usage cost (coal, nuclear, water, gas, oil, and diesel) and water usage cost of Eskom power stations and power purchases from non Eskom Generation.

The qualifying criteria for allowed primary energy costs are the same as for operating expenses. Only efficient costs will be allowed.

Coal transport costs incurred as a result of coal purchased from coal sources remote from the power stations are included in primary energy cost.

The total primary energy cost is subject to many variables such as:

- the total electricity to be supplied,
- the demand profile,
- where power is generated,
- from where power is purchased,
- the availability of the generation capacity and
- where the fuel is procured.

Provision has been made for a pass-through of prudently incurred primary energy costs (Refer to Section 6.1 below).

The primary energy costs must be based on central estimates of power generation volumes and prices and be consistent with the wholesale power sales budget.

5.6 Research and development costs

5.6.1 Core research and development activities, including demonstration relating to the production and supply of electricity, that is likely to benefit customers may be allowed, depending on criteria to be determined by the Energy Regulator from time to time;

5.6.2 The regulated entity shall have the onus to justify to the Energy Regulator that the expenses incurred conform to the above criteria;

5.6.3 The Energy Regulator shall have the final decision in allowing or disallowing an expense based on the above criteria;

5.6.4 As part of the analysis the Energy Regulator will examine Eskom research and development plans;

5.6.5 Research costs are also regarded as regulatory expenses and should be allowed up to a limit of 4% of total operating costs provided they result in the following:

- improved efficiency;
- extended plant life;
- lower operating costs;
- better load factor or power factor;
- better understanding of load behaviour;
- and relate to the design, construction, selection and operation of projects in the capital expenditure.

5.6.6The environmental projects allowable are as follows:-

- Those which relate to developing, designing, selecting and operating renewable energy sources;
- Those which relate to better usage of water, less pollution or global warming;
- Climatology projects related to environmental impact of regulated activities or forecasting of availability of natural resources and weather patterns.

5.7 Depreciation

Depreciation is calculated on the original cost of the RAB on a straight line basis over the useful economic life of the asset. The amortisation of revaluation amount is excluded as explained above (5.3.18)

5.8 Service Quality Incentives/Penalties

Service quality indices will be used for both transmission and distribution. The applicable index for transmission will be System Minutes (SM) and for distribution the index to be applied will be System Average Interruption Duration Index (SAIDI). The effect of this is that full pass-through of the related reliability programme will only apply if the performance targets are achieved. If the allowed costs are under spent, and the target materially under achieved, then there will be clawback of the under spend

5.8.1 Transmission Service Incentives/Penalties

A system minutes is defined as the aggregate of unsupplied energy over the system annual peak demand.

$$\text{System minutes} = \frac{\text{total unsupplied energy (MWh) x 60}}{\text{system annual peak demand}}$$

The SM<1 measures the underlying performance of Transmission for momentary interruptions (i.e. aggregated energy not supplied for smaller interruptions; *3s <SM<= 1*) and SM>1 will address the impact of major or sustained interruptions (where an individual interruption has a severity exceeding 1 system minute).

There will be a symmetrical incentive and penalty of a maximum value per annum to be determined. The value will be calculated on a sliding scale basis over the three year MYPD period. This figure calculated agreed will be added to the allowed revenues calculation.

The service incentive scheme for system minutes will be applied as follows:

- System minutes will be calculated on maximum demand value for the previous year;
- The system minute peak demand will exclude exported power;
- The interrupted load is the actual load interrupted (estimated) and not the peak demand or transformer capacity interrupted. Where the interruption is short, SCADA information at the time is used. Where the interruption is long, a load profile based on historical information is used;
- All interruptions caused by transmission events are counted;
- Interruptions (including load shedding) caused only by generation events or generation shortages are not counted where the transmission system can be shown to have appropriately applied its system operations rules;

- Interruptions caused by customers are not counted, where these are correctly cleared by Eskom (however if breaker fails or protection does not work correctly it is counted);
- The system minute count is completed when the transmission network is able to supply the load (i.e. not the additional time it takes for the distributors to reconnect customers, this is not under the control of transmission, and the actual load is difficult to quantify);
- A 12-month moving average starting on the 1st April each year will be applied in determining the actual values of performance;
- At the end of each of the three years, the penalty/reward will be determined and accrued to Transmission;
- Each System Minute measure has 50% of the weight / value;
- Targets, ceilings and floors are set statistically on historic performance and aligned with Eskom external targets.

5.8.2 Distribution Service Incentives/Penalties

The key performance indicator will be a single index called System average interruption duration index (SAIDI) that gives a good overall indication of the utility's performance. SAIDI is a measure of both the frequency of interruptions and the duration of interruptions. The formula for SAIDI is defined as follows:

$$\text{SAIDI} = \text{SAIFI} \times \text{CAIDI}$$

SAIFI – System Average Interruption Frequency Index
CAIDI – Customer Average Interruption Duration Index

The formulae for both SAIFI and CAIDI are defined as follows:

$$\text{SAIFI} = \frac{\text{total number of customer interruptions p.a}}{\text{total number of customers served}} \quad \textit{and},$$

$$\text{CAIDI} = \frac{\text{customer interruption duration p.a}}{\text{total number of customer interruptions}}$$

The service incentive scheme for SAIDI will be applied as follows:

- For the MYPD 2 control period, the SAIDI referred to, is inclusive of both controllable and uncontrollable events (e.g. transmission-caused, force majeure events, thefts and customer-caused events) in order to ensure consistency with historical performance;

- However any transmission events of magnitude >1 system minute, as well as any force majeure events resulting in SAIDI hour greater than one, is to be excluded from the calculations;
- Incentives payable to Eskom should not be larger than the value of improved performance, and should also not be less than the cost to achieve it;
- The incentive targets set need to have relevance to the value of the improved performance;
- Incentives/penalties should be capped in order to limit the exposure of customers to higher prices;
- New electrification customers will be excluded from the calculation of SAIDI;
- Eskom Distribution to report regularly, indicating their reliability expenditure and their SAIDI to date against the target. This report must also include commentary on the causes of any improvement or deterioration.

5.9 Energy Efficiency and Demand Side Management (EEDSM)

EEDSM refers to energy efficiency and demand side management. It is the planning, implementation, and monitoring of distributors activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to distributors-administered programmes. The allowed revenue provides an allowance for EEDSM expenditure based on the EEDSM project plan submitted by Eskom. The following formula must be used to determine the EEDSM application.

5.9.1 EEDSM Formula:

RR_{EEDSM}= ($MW_{target\ savings}$ x AC) + other cost + M&V cost – additional EEDSM funding

5.9.2 RREEDSM: Revenue Requirement for EEDSM;
5.9.3 MWtarget savings: Target Megawatt Savings per annum;
5.9.4 AC: Avoided cost of Generation, Transmission or Distribution;
5.9.5 Other cost: Marketing and communications, Research and development;
5.9.6 Measurement and Verification cost (M&V): All M&V cost for EEDSM projects;
5.9.7 Additional EEDSM funding: All funding outside electricity tariffs for EEDSM projects;

5.9.8 Avoided costs are an estimate of the costs that would be avoided as a result of the need to produce and distribute less electricity to our customers in conjunction with energy efficiency programs;

5.9.9 Any additional funding received from other donors on EEDSM will be subtracted from total revenue required by Eskom on EEDSM.

The rules for determining the allowance are as follows:

5.9.10 MW target savings and breakdown per technology are determined by the Energy Regulator based on Eskom's EEDSM project plan;

5.9.11 The avoided cost applicable to EEDSM projects is determined by the Energy Regulator in consultation with Eskom;

5.9.12 Over achievement of the EEDSM target will be rewarded based on a R/MW amount that is determined by the Energy Regulator;

5.9.13 Under achievement of the EEDSM target will be clawed back using the same R/MW as for over achievement;

5.9.14 Any additional funding received from other donors on EEDSM will be subtracted from total revenue required by Eskom on EEDSM.

5.10 Economic Assumptions

Recognising that electricity is an essential input into various economic activities in the economy and that the demand for, and supply of electricity has an impact on the level of economic activity, it is important that the impact of these economic parameters is considered in the revenue determination.

NERSA will take into account the impact of the following economic parameters on the outcome of the revenue determination on electricity prices and vice versa:

- *Level of economic activity as measured by Gross Domestic Product (GDP)*: The level of economic activity measured by the movements in GDP is a major input in Eskom's planning both in the long term and short term. Thus, any short-term and long-term movements in the level of economic activity must be taken into account in making a revenue determination. This is the case taking into consideration that electricity represents an input cost into major economic activities such as manufacturing; mining; agriculture; transport and general business (provision of services such as telecommunications, banking and retail services). It is important that any revenue determination impacting on electricity prices takes cognisance of the movements in the level of economic activity and the impact thereon resulting from changes in electricity prices. Any correlation that exists between the interaction of demand and supply of electricity (resulting in a price) and the level of economic activity must be established and taken into account in the revenue determination process.

- *Level of Interest Rate*: interest rate represents the cost of debt to the respective economic agents in an economy. Different categories of interest rates exist in the South African economic context. The main being the Repo Rate, determined by the South African Reserve Bank and the Prime Interest Rate, determined by the commercial banking sector. These rates are mainly quoted for borrowing that affects the household segment of the economy. Interest Rates for the business/corporate debt are determined in the debt capital and bond markets. For purposes of possible corrective measures in the Regulatory Clearing Account and the Capital Expenditure Carry-over Account, prime rate will be used as measure for the time value of money issues for any funds that are reflected in these accounts.

- *Inflation*: All inflation adjustments will be based on the average financial year consumer inflation. The use of consumer inflation is done in order to make sure that the efficiency incentives are not lost. The consumer price index (CPI) will be used as a measure of inflation. It is noted that in the running of an efficient business, with optimal planning, electricity prices will to a large extent increase at the same level at as general prices. However there could be periods of external shocks which affect input costs.

- *Exchange Rate*: The foreign currency risk is the risk of changes in the exchange rate. A lot of important costs in the Eskom's infrastructure project will be taken in foreign currency although Eskom's revenue is earned in rands. Where necessary there need to be adjustments to cater for the fluctuations in the average exchange rate between the rand and other major foreign currencies which Eskom has international commercial transactions.

All these parameters will be average financial year forecasts independently sourced by NERSA.

6. Risk Management Device

The risk of excess or inadequate returns is managed by:

- Adjusting the allowed revenue upwards when the cash flow estimates will not result in an adequate interest cover;
- Deflating the nominal estimates of the regulated entity using the CPI forecasts and after the event (ex post) applying the actual (ex post) CPI inflation rate to the allowed revenue;
- Allowing the pass-through of prudently incurred primary energy costs;

- Adjusting capital expenditure forecasts for cost and timing variances;
- Adjusting the Distribution revenue for sales volume variances;
- Adjusting the Distribution revenue for residential customer number variances.

In addition, a last resort mechanism is put in place to trigger a re-opener of the price determination when there are significant variances in the assumptions made in the price determination.

6.1 Treatment of Primary Energy

The rules for Eskom to purchase electricity from IPPs are as follows:

1. Efficient purchases from IPPs will be allowed as a full pass-through, however;
2. to mitigate the risk of inefficient procurement, the Energy Regulator will review power purchase agreements (PPAs) between Eskom and IPPs before they may be signed;
3. the pass-through will be reviewed by NERSA to determine the efficiency and prudency with which pass-through costs have been incurred above the MYPD allowance;
4. the variances (difference between MYPD allowed costs and actual costs), together with reasons thereof, will be presented to NERSA 2 months prior to year-end based on actual costs for 9 months and projections for 3 months to year-end; and
5. This variance after review by NERSA will be debited / credited into the IPP Regulatory Clearing Account.

Rules for Eskom's gas turbine generation costs (e.g. OCGTs)

Changes in the OCGT total costs may be caused by the change in the unit cost[3] of fuel used in running OCGT plants or by the volumes[4] of electricity produced from such plants. These changes are dealt with as follows:

<u>Changes to the unit cost of fuel</u>

Where variances are caused by changes to the unit cost of fuel, a full pass-through will be allowed but limited to volumes allowed by the Energy Regulator i.e. the pass-through value will be equal to gas turbine production volumes of electricity in MYPD production plan multiplied by

[3] The cost of fuel as allowed in the MYPD determination compared to the actual cost of fuel incurred
[4] Volumes that were assumed in the MYPD determination compared to the actual volumes of electricity consumed from running OCGT plants

the difference between the actual unit price of fuel and the MYPD unit price of fuel.

Eskom will provide NERSA with actual unit costs of running an OCGT plant on a quarterly basis which NERSA will verify and compare to the unit costs as approved in the MYPD plan.

This pass-through will only be allowed after consideration of risk mitigation strategies presented by Eskom.

There are various risk mitigation options to manage the volatility of uncontrollable costs such as hedging contracts. However, some risk mitigation options are inherently risky themselves. NERSA's view is not to prescribe to Eskom a risk mitigation option but rather to expect Eskom to be prudent in the management of its costs.

Changes to planned electricity production from OCGTs

Eskom is expected to have control over the output of its OCGT plants based on constraints within the entire system. The rules for such variances in output will be as follows:

- Eskom will present NERSA with its production plans for the planned utilization of the OCGT plants with its MYPD application;
- Quarterly Eskom will provide NERSA with the actual utilization and an explanation for any deviation from the original plans;
- NERSA will review the explanations provided and where they are considered prudent approve the pass-through of the cost of the above plan output.

NERSA will not place any limitations on the load factors for OCGT plants but wants to ensure that these are run only when necessary after due consideration of the other available options as prescribed in the Grid Code. Where this cannot be demonstrated to the satisfaction of the Energy Regulator, the resultant costs will not be allowed as a pass-through.

Coal procurement rules

The rules for coal procurement are as follows:

1. Coal will be treated as a single cost centre without differentiating between the various coal sources (i.e. cost plus contracts, fixed price contracts etc.) – coal purchases are seen as a portfolio to be managed using various options;
2. Eskom will, however, submit a full breakdown of coal procurement and consumption plans and costs to the Energy Regulator with its MYPD application (similar to current practice);
3. The Energy Regulator will analyse the plans and approve an average R/ton cost of coal for each of the MYPD years. This price will then become the “benchmark” cost[5];
4. towards the end of each year i.e. 3 months prior to year end, Eskom will submit its actual year-to-date costs with projections to year end;
5. NERSA will then compare the actual R/ton cost to its approved benchmark cost using a Performance Based Regulation [6](PBR) formula that calibrates incentives and penalties for performance:

    a. this requires that gains and losses resulting from good or bad procurement be shared among Eskom and its customers;
    b. Sharing will depend on the basic rule that “the risk will be allocated to the entity more able to manage such risk”.

6. A weighted alpha will be set, sharing the risk between Eskom and its customers – alpha being any number between 0 and 1; alpha will be set at the time of making the decision of the MYPD to avoid creating uncertainty. Alpha will be based on the information provided by Eskom, the international coal prices, and the general economic outlook;
7. the PBR formula is:
   Maximum amount to be allowed for pass-through
   = *Alpha* x actual cost + (1 – *Alpha*) x Benchmark cost

The amount determined will be allocated to the Regulatory Clearing Account.

The rules for pass-through of other primary energy costs

The other primary energy costs (nuclear, hydro, other costs) are considered to be stable and less risky and are therefore not allowed as pass-through. It is considered that Eskom must be able to reasonably accurately forecast these costs.

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[5] In determining the Benchmark costs NERSA will use the information contained in the NIRP, international coal prices and an analysis of Eskom’s coal purchase plans

[6] The PBR formula is a formula that will be used to determine the amount of pass-through to be allowed to Eskom or customers after consideration of the entity more able to manage the risk.

6.2 Treatment of variance on capital expenditure

To accommodate the unstable environment in which the capital expenditure will be undertaken, the approach for adjusting capital expenditure cost and timing variances will be as follows:

1. Eskom will report six monthly to NERSA on its capital expenditure programme, providing information on timing and cost variances;
2. At the end of each financial year Eskom will provide NERSA with a final reconciliation report of the actual capital expenditure incurred;
3. Upon receipt, NERSA will record all efficient capital expenditure above or below the approved amount on the capital expenditure carryover account (CECA) and quantify Eskom's exposure;
4. Balances on the CECA will be adjusted as follows:
    a) If a return on the CECA balance (i.e. rate of return calculated on balance of this account) is below a quarter of the allowed return, the CECA balance will be carried forward to the following year without adjusting the allowed return.
    b) At the end of the second year of the MYPD, if the accumulated CECA balance for year 1 and 2 is greater than or equal to a quarter of the combined returns for both years, an immediate pass-through will be allowed in the third year of the MYPD.
    c) If the return on CECA balance remains under a quarter of the combined returns for MYPD, Eskom will be allowed to recover the entire over- recovery in the next MYPD[7].

5. At the end of the MYPD, if there is any under expenditure compared to forecasted capital expenditure, the value of the RAB will be adjusted downwards for investments not undertaken and the revenues in the next MYPD will be adjusted to compensate for the return earned on unused funds in the previous MYPD, for any over expenditure compared to forecasted capital expenditure, the balance would be added to the RAB and Eskom will be allowed additional returns to recover the costs of the over expenditure at the start of the next MYPD. This approach will effectively remove from Eskom any potential windfall losses or gains should the approved capital expenditure differ from the actual expenditure.

6.3 Triggers for re-opening the MYPD

1. Withdrawals from the balance in the Regulatory Clearing Account (RCA) be controlled with a review level of 3% of the allowed revenue and a re-open level of 10% of the allowed revenue;

[7] The MYPD period is 3 years (1 April 20010– 31 March 2013)

2. In addition actual earnings will be tracked and used to trigger a re opener in a band of WACC +/- 1%;
3. That RCA balance and actual earnings be reported per ring fenced Eskom licensed entity and be monitored by the Energy Regulator quarterly;
4. The year-end projected price impact of the application of the draw down from the RCA balance be reported by Eskom on a quarterly basis;
5. That IPP purchases, imports and exports be considered as part of the Generation Control Mechanism.

6.4 The Regulatory Clearing Account (RCA)

The RCA is used to debit/credit the allowable portion of coal costs variances as calculated through the PBR formula and all other costs variances that have not been dealt with in the MYPD mechanism. The RCA shall be used as follows:

i. The Regulatory Clearing Account will be created at the beginning of the year and continuously monitored. The evaluation of the account (for the purpose of determining the pass-through) will be done towards the end of Eskom's financial year (approximately 2 months prior to year end) with actuals for the 9 months and Eskom projections to year end;
ii. The Regulatory Clearing Account balance will be measured as a percentage of total allowed revenue;
iii. If the RCA balance is less than or equal to 2% of the allowable revenue, then there will be no immediate pass-through adjustment but the RCA balance will be carried over to the next financial year;
iv. If it does not reach the 2% by the end of the MYPD then the balance is carried over into the next MYPD;
v. If the RCA balance is between 2% and 10%, the amount is allowed as a pass-through in the next financial year without the need for a full stakeholder consultation process;
vi. If the balance is greater than 10 % of the allowable revenue then there will be a full stakeholder consultation process before any pass-through is allowed;
vii. The adjustments to be included in the RCA will be approved by the Energy Regulator in terms of the MYPD mechanism. In that manner the balance of the RCA will have been approved by the Energy Regulator for pass-through. The Energy Regulator will only have to determine the timing of when it should be passed through.
viii. Whilst the plan is to use the account towards year-end, there is a need to have this account updated quarterly so as to use it for regular alerts to customers of any possible adjustment in the coming year;

ix. Eskom, will on a quarterly basis, present the Energy Regulator with possible adjustments based on the mechanism, the costs to date and the projections to year-end;

x. The Energy Regulator will then review Eskom's submission and have it published on both the Eskom and the NERSA websites; and

xi. Because the review is done prior to year-end and before the audit of Eskom's accounts has been performed, a further review will be performed upon receipt of audited statements from Eskom.

End.