Suruhanjaya Tenaga
Energy Commission

Guidelines

On Tariff Determination Under Incentive Based Regulation For Tenaga Nasional Berhad

[Electricity Supply Act 1990 (Act 447)]

ELECTRICITY SUPPLY ACT 1990

[*Act 447*]

GUIDELINES ON TARIFF DETERMINATION UNDER INCENTIVE BASED REGULATION FOR TENAGA NASIONAL BERHAD

GP/ST/No.2/2016

IN exercise of the power conferred by Sections 26 and 50C of the Electricity Supply Act 1990 [*Act 447*], the Commission makes the following Guidelines:

Citation and Commencement

1. These Guidelines may be cited as the Guidelines on Tariff Determination Under Incentive Based Regulation for Tenaga Nasional Berhad:

2. These Guidelines shall come into operation on the date of its registration.

Purpose and Application of the Guidelines

3. These Guidelines describes the methodology, principles, procedures and requirements that shall be complied by Tenaga Nasional Berhad in the submission of the electricity tariff proposal or revision as required under Section 26 of the Electricity Supply Act 1990.

The Tariff Determination Framework

4. The framework for tariff determination shall be based on eleven (11) Regulatory Implementation Guidelines ("RIG") as follow:

   i) RIG 1, which defines the business entities of TNB, as in **ANNEX A**;
   ii) RIG 2, which defines the tariff setting framework, as in **ANNEX B**;
   iii) RIG 3, which sets the revenue requirement principles, as in **ANNEX C**;
   iv) RIG 4, which sets the Weighted Average Cost of Capital of TNB, as in **ANNEX D**;

v) RIG 5, which establishes the operating cost, capital cost, asset and consumption templates, as in **ANNEX E**;

vi) RIG 6, which establishes the incentive framework for operational performance, as in **ANNEX F**;

vii) RIG 7, which defines the cost allocation principles, as in **ANNEX G**;

viii) RIG 8, which establishes the imbalance cost pass through mechanism, as in **ANNEX H**;

ix) RIG 9, which defines the tariff design principles, as in **ANNEX I**;

x) RIG 10, which establishes the regulatory accounts process, as in **ANNEX J**; and

xi) RIG 11, which establishes the process for determining the revenue requirement and tariff, as in **ANNEX K**.

Notice by the Commission

5. The Commission may issue written notices from time to time in relation to these Guidelines.

Amendment and Variation

6. The Commission may at any time review, amend, modify, vary or revoke these Guidelines.

Dated: 04 **May 2016**

DATUK IR. AHMAD FAUZI BIN HASAN
Chief Executive Officer
for Energy Commission

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ANNEX A

REGULATORY IMPLEMENTATION GUIDELINE 1

- RIG 1 -

Defines business entities; specify functions of each business entity; specify the flow of funds between business entities.

1. Objective

The objectives of RIG 1 are as follows:

- Establish the business entities of TNB which will be subject to incentive-based regulation;
- Define the functions of each of the business activity; and
- Specify the flow of funds between the business activities.

2. Business Entities of TNB

There are two broad choices for establishing the business entities of TNB, the Simple Model and the Market Managed Model.

2.1 Simple Model

In the Simple Model, TNB's business is categorised into three business entities, which are Generation, Transmission and Customer Services. These three business entities are defined below

- Generation: This business entity includes the management and operation of generation plants owned by TNB (TNB generation), the procurement of generation supply from various Independent Power Producers (IPPs) connected to TNB's transmission system and TNB's energy procurement department. The objective of Generation is to ensure that there is sufficient generation supply to meet the demand requirement of electricity customers.

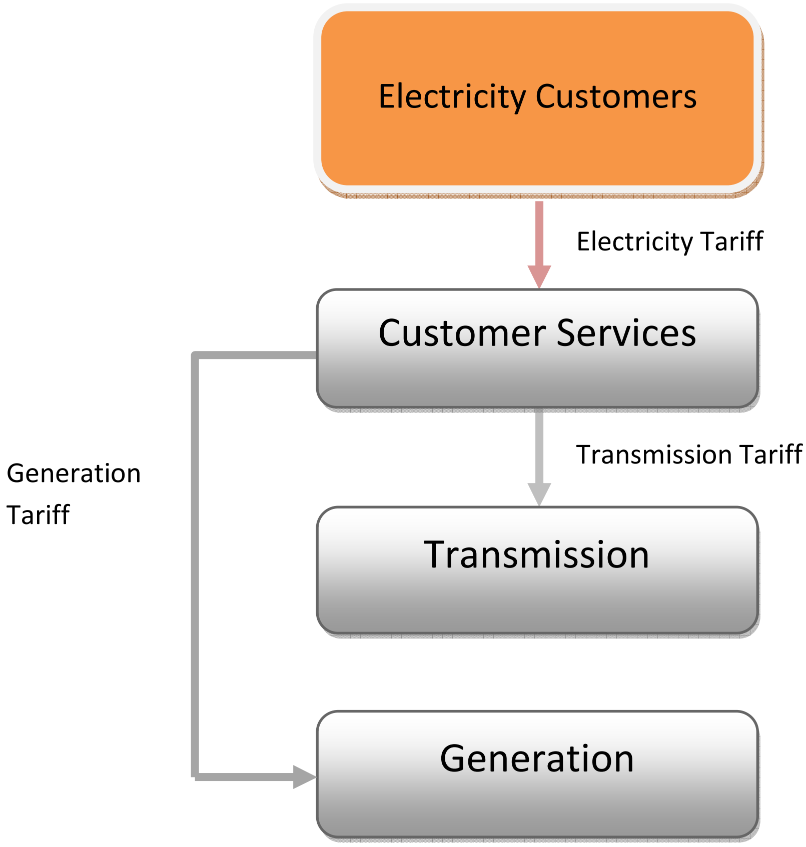
- Transmission: This business entity includes the management, maintenance and development of the TNB transmission system and system operations for the transmission of electricity to end customers.

- Customer Services: This business entity includes the management, maintenance and development of the distribution system and the sale of electricity to customers.

The Customer Services business entity charges electricity customers a tariff for the use of electricity. This tariff is a bundled tariff and incorporates a charge for Generation, Transmission and Customer Services. Customer Services receives all the tariff revenue from electricity customers and subsequently pays the Transmission business entity its share of revenue based on Transmission Tariffs and pays Generation its share of the revenue received based on Generation Tariff.

The flow of funds between the three business entities is shown below.

FIG: Flow of funds for Simple Model



The three business entities of Generation, Transmission and Customer Service will be ring fenced with separate accounts.

2.2 Managed Market Model

In the Managed Market Model, TNB's business is categorised into five business entities, which are TNB Generation, Single Buyer, Transmission, System Operator and Customer Services. These business entities are defined below:

- Single Buyer: This business entity comprises the functions of the existing TNB's Energy Procurement Division. The main function of the Single Buyer is to procure electricity from IPPs and TNB Generation based on the terms of the PPAs entered into with the IPPs and Service Level Agreements (SLAs) entered into with TNB Generation. The Single Buyer dispatches TNB's generation units and the IPPs based on a dispatch merit order. The dispatch merit order is based on the heat rate, fuel costs and variable operating costs of all the generation plants available (including all IPPs and TNB generation plants) for dispatch. The Single Buyer produces the day-ahead dispatch.

- TNB Generation: This business entity includes the ownership, management and operation of generation plants owned by TNB. TNB Generation contracts with the Single Buyer for the sale of electricity based on Service Level Agreements (SLAs).

- Transmission: This business entity includes the management, maintenance and development of the TNB transmission system for the transmission of electricity to end customers. Transmission system planning is done by the Transmission business entity.

- System Operator: This business entity includes the current functions of transmission system operations of TNB.

- Customer Service: This business entity includes the management, maintenance and development of the distribution system and the sale of electricity to customers.

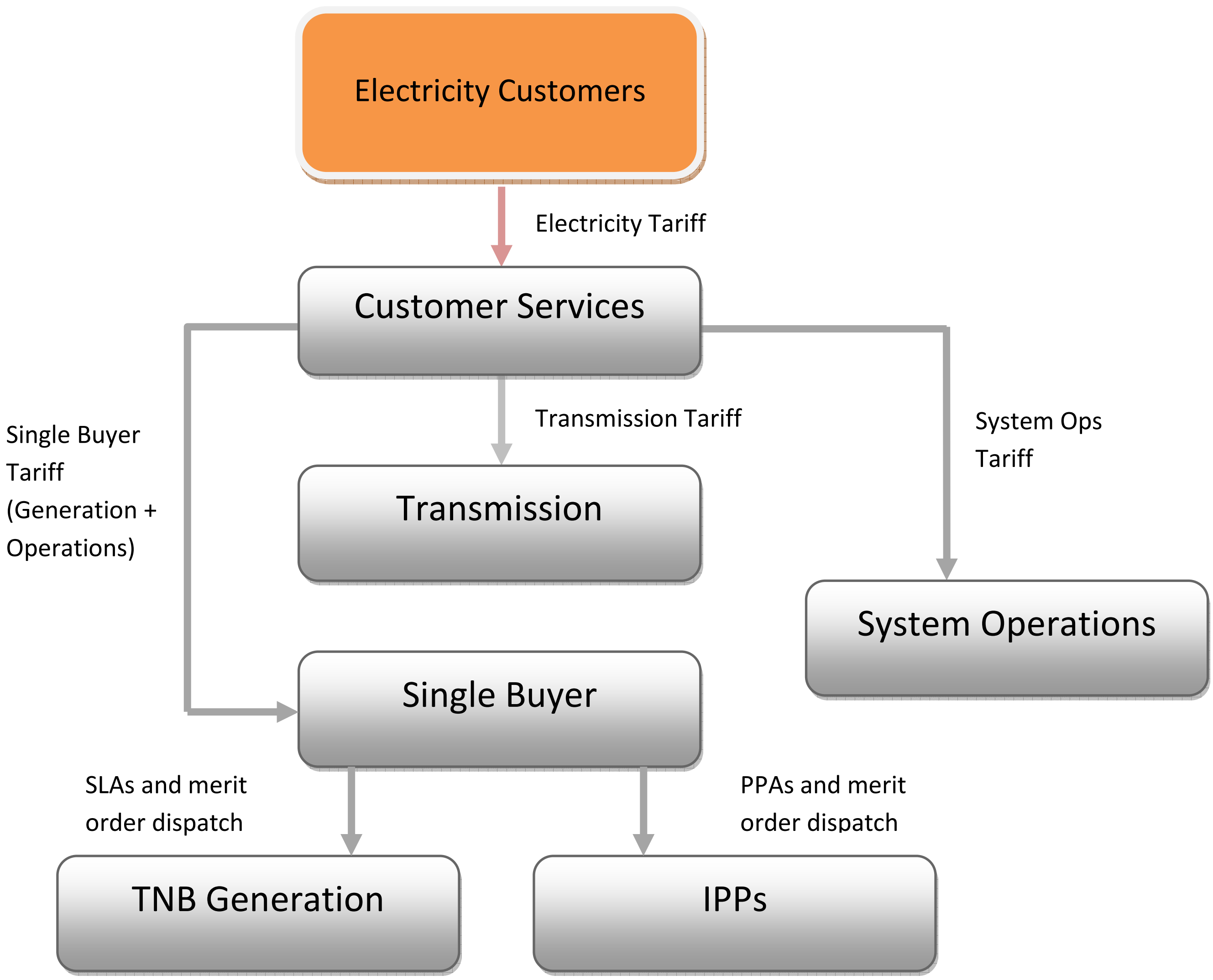
In addition to the five Business entities of TNB, the IPPs are collectively the sixth business entity, contracting with the Single Buyer for sale of electricity.

The Customer Services business entity charges electricity customers a tariff for the use of electricity. This tariff is a bundled tariff and incorporates a charge for all Generation (IPPs, TNB generation and cost of Single Buyer), Transmission, Transmission System Operations and Customer Services. Customer Services receives all the tariff revenue from electricity customers and subsequently pays the Transmission and the System Operations business entity its share of revenue based on set Transmission Tariffs and tariff for System Operations.

The Single Buyer charges a Single Buyer Tariff to the Customer Services business entity, comprising a Generation component (based on forecasts costs of generation determined by the capacity payment in the IPPs and SLAs and all variable generation costs based on the merit order dispatch) and an Operations component (based on the operating costs of managing the operations of the Single Buyer). The Single Buyer receives the Generation Revenue and pays TNB Generation and the IPPs.

The flow of funds between the five TNB business entities and the IPP’s is shown below.

FIG: Flow of funds for Managed Market Model



The five business entities of Single Buyer, TNB Generation, Transmission, System Operations and Customer Service will be ring fenced with separate accounts.

3. Recommendation

The Commission's preference is to adopt the Managed Market Model. This is because;

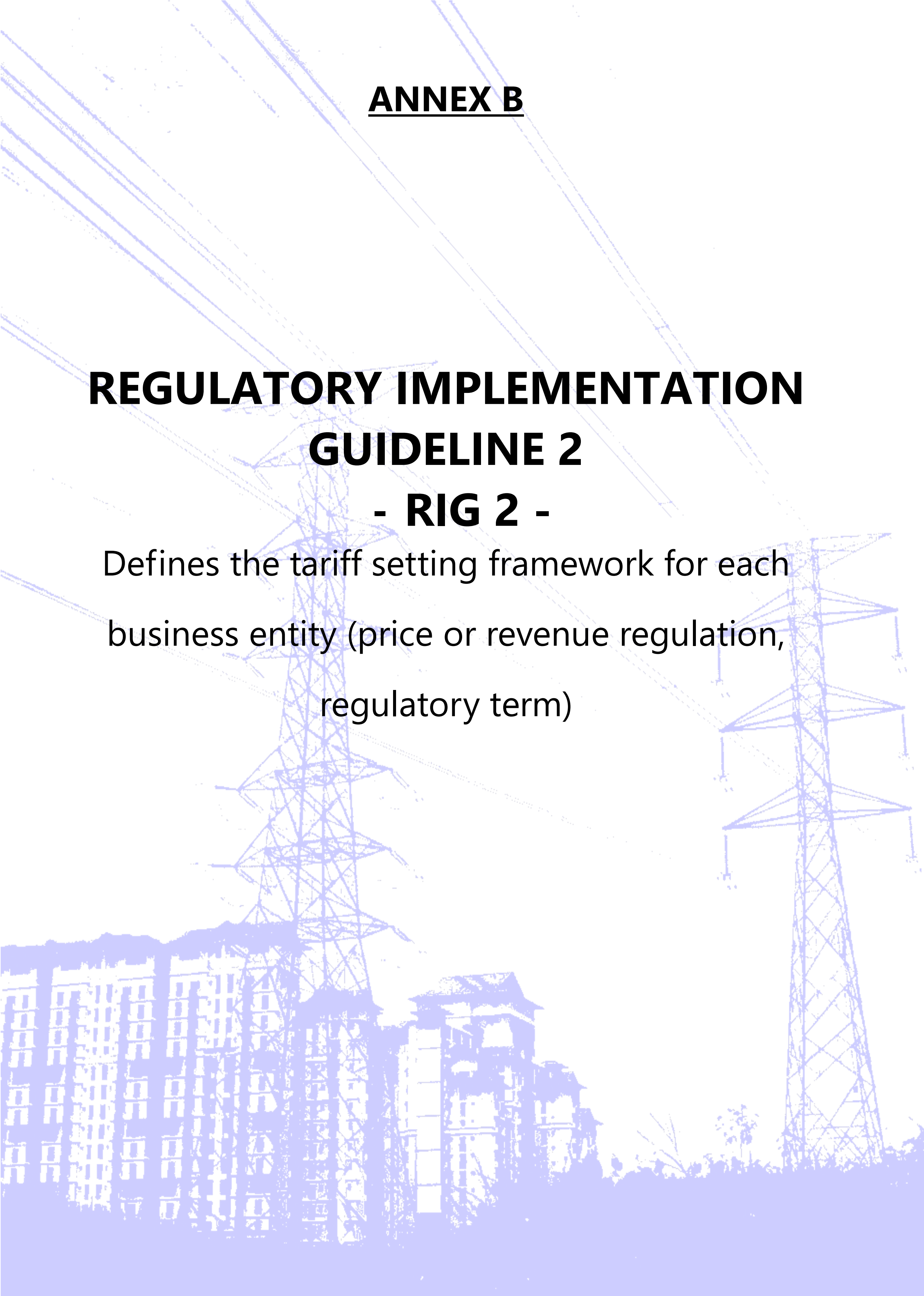
- the Managed Market Model is consistent with TNB's operations;
- enhances transparency between TNB generation and IPPs; and
- is broadly consistent with the recommendations of the MyPOWER Corporation.

The Managed Market Model requires the operating rules for the Single Buyer to be established upfront. The principles for the Single Buyer and the high level rules for dispatch are incorporated in the current Grid Code. However, further work needs to be done to develop in detail the operating procedures (or the Managed Market Rules) to ensure transparency and clear guidelines for the Single Buyer to follow in preparing the day-ahead dispatch schedule. The rules for producing the day-ahead dispatch schedule should be comprehensive with clear guidelines established upfront which articulate how the Single Buyer will respond to upset conditions, such as fuel curtailment or the need to re-optimise dispatch based on fuel supply (or fuel contract) issues.

The separation of the Single Buyer and System Operations will maintain a proper check and balance with the Single Buyer focusing on developing the rules for this Managed Market Model and taking on a more strategic role and ensuring transparency, and System Operations focusing on real time operations ensuring system security and stability on a real time basis. The Single Buyer currently has the relevant knowledge on fuel security and availability and expertise on the contractual terms of the PPAs and the SLAs to enable it to take a more strategic view of dispatch.

The Single Buyer and the System Operator could also be merged into a single business entity responsible for both real time system dispatch and security and producing the day-ahead dispatch based on the managed market rules. However our preference is to initially have separation of duties between System Operations and Single Buyer to ensure that both entities are focused on their respective roles. Once the rules of this managed market are well established, System Operations and the Single Buyer can be merged if required.

Finally, the recommended model will require some adjustments to TNB's divisional accounting framework, as the costs (and business activities) of the Single Buyer and System Operations will need to be separately identified and ring fenced from other parts of the business.



ANNEX B

REGULATORY IMPLEMENTATION GUIDELINE 2

- RIG 2 -

Defines the tariff setting framework for each business entity (price or revenue regulation, regulatory term)

1. Objective

The objectives of RIG 2 are as follows:

- Establish the tariff setting framework for each TNB business entity operating in the Managed Market Model; and
- Set the Regulatory Term for each of the five TNB business entities.

2. Tariff Setting Framework

There are three choices for setting the tariffs which the five TNB business entities can choose from. These choices are outlined below:

2.1 Price Cap

Under a pure Price Cap regulatory framework, price (and price path) is set for the Regulatory Term based on forecasts of cost and electricity sales. The calculation of price and price path under a Price Cap regime is outlined in Regulatory Guideline Number 3 (RIG 3).

Business entities operating under a Price Cap regime are exposed to all revenue risk based on actual electricity sales varying from forecasts of electricity sales used to set price and price path under RIG 3. That is, the revenue for business entities will be based on actual electricity sales, which may be different to projected revenue based on initial forecasts electricity sales used to set price as per RIG 3. This is because prices are not adjusted within a Regulatory Term for actual electricity sales outcome.

2.2 Revenue Cap

Under a pure Revenue Cap regulatory framework, annual revenue is set for every year of the Regulatory Term. The calculation of annual revenues under a Revenue Cap regime is outlined in RIG 3.

Business entities operating under a Revenue Cap regime are not exposed to any revenue risk. This is because if actual revenue is different to forecast revenue due to differences between actual and forecast electricity sales, prices are adjusted to make up for the revenue difference.

2.3 Actual cost

Under an Actual Cost recovery model, the regulated entity is allowed to recover all of its actual costs. Prices adjust to reflect changes in costs to ensure that the regulated entity does not earn less (or more) than the cost of providing services. Typically, operators of companies managing the wholesale market operate under an Actual Cost recovery regime.

2.4 Hybrid Model

The Hybrid Model is a combination of a Price Cap and a Revenue Cap regime or alternatively a combination of all three regimes as discussed previously (Price Cap, Revenue Cap and Actual Cost). The Hybrid Model offers the flexibility to apply either a Price Cap or Revenue Cap or Actual Cost to different parts of the regulated value chain. For example, a regulated vertically integrated electricity utility may choose to apply a Price Cap where costs vary with electricity sales and Revenue Cap where costs of service are largely fixed and do not vary in the short term with electricity sales.

3. Analysis of the options and recommendation on Tariff Setting Framework

Typically, regulated distribution businesses operate under a Price Cap regime, with transmission businesses operating under a Revenue Cap regime. This is because transmission costs are largely fixed and do not vary with electricity sales in the short to medium term. However, distribution businesses' costs vary more with electricity sales due to customer connections and localised capacity expansions to meet electricity demand growth.

Generation costs comprise largely of plant costs and fuel. In competitive markets, the recovery of generation costs depends upon the nature of the market. Under a market pool, recovery of generation costs depends primarily upon pool price, bidding strategy of market participants and the contracting strategy of the generator. Under a regulated model, like that of Singapore for domestic customers, generators work under a pure Price Cap regime. In Australia, initially when the domestic market was regulated generators operated under vesting contracts which was a pure Price Cap regime.

The Commission's recommendation is the following:

3.1 Bundled tariff for final electricity customers

It is expected that Customer Services will initially charge a bundled tariff to electricity customers. This bundled tariff will be the sum of a tariff component applicable for Customer Services plus tariff components for Transmission, System Operations and Single Buyer Costs (including a generation specific tariff and other operating cost specific tariff).

The separate identification of costs and revenues for each TNB business entity as specified in RIG 1 under the managed market model will enable disaggregation or unbundling of tariff components for final customers should this be required at a later date.

3.2 Customer Services

It is intended that a pure Price Cap regime will apply to Customer Services. The Customer Services component of the bundled tariff will be fixed for the Regulatory Term, and will not vary with changes in electricity sales within the Regulatory Term.

The price which Customer Services charges customers will be determined in accordance with RIG 3.

However, note that the bundled tariff charged to electricity customers may vary due to the revenue cap arrangements that will apply for the Transmission business entity, the System Operator entity and/or the Single Buyer entity, or the Actual Cost arrangements applying to the Single Buyer entity.

3.3 Transmission

Transmission will operate under a Revenue Cap regime. Any annual revenue shortfall or surplus will be recovered or passed on to electricity customers in the next regulatory term to the final bundled price which is charged by Customer Services.

3.4 System Operations

System Operations will operate under a Revenue Cap regime. Any annual revenue shortfall or surplus will be recovered or passed on to electricity customers in the next regulatory period to the final bundled price which is charged by Customer Services.

3.5 Single Buyer

The Single Buyer will operate under a Revenue Cap regime for its own operating costs, combined with an Actual Cost regime for generation specific costs.

Under the Actual Cost regime, the Single Buyer will pass on all actual costs of procuring electricity from the IPPs and TNB Generation (including fuel (both coal and gas), capacity payments and other costs associated with the terms and conditions of the PPAs, SLAs and other fuel procurement contracts i.e. TNB Fuel Services Sdn. Bhd. coal contracts) to Customer Services. The Single Buyer will also include in its actual cost the cost of procuring electricity from renewable generation and all other non IPP and TNB generation entities. These costs will then flow through to electricity customers via the bundled tariff. Actual Cost adjustments will occur on a six monthly basis.

The Single Buyer acts like a clearing house in the absence of a market pool and optimises generation costs based on efficient dispatch of generation. In a market pool model, the retailer pays actual pool costs. Therefore, the concept of subjecting the Single Buyer to an Actual Cost regime is similar to a market mechanism, where market price is set based on dispatch. The difference in the proposed Actual Cost regime for the Single Buyer is that generators get compensation based on actual cost of generation based on dispatch and contracts, rather than a marginal price of generation. This proposal is similar to a cost base pool, which operates in some countries.

Other operational and capital related costs of running the Single Buyer operations (including an allocation of joint costs (if any)) will be subject to a Revenue Cap regime. Any revenue shortfall or surplus will be recovered or passed on to electricity customers in the next regulatory term to the final bundled price which is charged by Customer Services.

4. Worked example

In this scenario consider the final bundled average tariff to be 25 s/kWh. This comprises of 10 s/kWh for Customer Services, 4.8 s/kWh for Transmission, 0.2 s/kWh for System Operations and 10 s/kWh for the Single Buyer. The 10 s/kWh average tariff for the Single Buyer comprises 9.8 s/kWh for generation specific costs (including fuel etc) subject to an Actual Cost regime, and 0.2 s/kWh for other operational and capital costs subject to a Revenue Cap regime.

The final bundled average tariff of 25 s/kWh has been based on the cost forecasts of the various business entities and 100 kWh forecasts of electricity sales. The forecast revenue position for all business entities is shown in the table below.

FIG: Forecast revenue and sales

	Bundled	Customer Services	Transmission	System Operations	Single Buyer	
					Generation specific	Operational
Sales forecast (kWh)	100	100	100	100	100	100
Average Tariff (s/kWh)	25	10	4.8	0.2	9.8	0.2
Revenue Forecast (RM)	25	10	4.8	0.2	9.8	0.2

If the actual electricity sales are equal to forecast and the actual costs of the Single Buyer are same as forecast costs, then all business entities are revenue neutral. Under this scenario, there will be no change to the following year's bundled average tariff.

Now consider the scenario where actual outcome is different to forecast as follows:

- actual electricity sales are 110 kWh, 10 kWh higher that forecast; and
- actual cost of single buyer is higher by 0.7 RM, due to higher sales requiring additional generation.

Under this scenario, the revenue position of each Business Entity is the following.

FIG: Actual revenue and sales

	Bundled	Customer Services	Transmission	System Operations	Single Buyer	
					Generation specific	Operational
Actual Sales (kWh)	110	110	110	110	110	110
Average Tariff (s/kWh)	25	10	4.8	0.2	9.8	0.2
Actual Revenue (RM)	27.5	11	5.28	0.22	10.78	0.22
Forecast revenue (RM)	25	10	4.8	0.2	9.8	0.2
Revenue cap / Actual (RM)		N/A Price Cap	4.8 Revenue Cap	0.2 Revenue Cap	10.5 Actual Cost	0.2 Revenue cap
Surplus / (deficit) RM	0.8	0	0.48	0.02	0.28	0.02

In this scenario:

- the Customer Services business entity is allowed to retain the surplus of 1 RM as it operates under a Price Cap regime;
- the Transmission business entity over recovers by 0.48 RM. As Transmission operates under a Revenue Cap this must be returned to customers in the following regulatory term;
- the System Operations business entity over recovers by 0.02 RM. As System Operations operates under a Revenue Cap this must be returned to customers in the following regulatory term;

- the actual costs of the Single Buyer with respect to generation specific costs (fuel etc) were 10.5 RM due to increased generation, 0.7 RM higher than expected. Given that the generation specific tariff recovered 10.78 RM, the generation specific tariff over recovered by 0.28 RM. This must be returned to customers in the following regulatory term[1]; and
- the other operations of the Single buyer over recovered by 0.02 RM. As this part of the Single Buyer is subject to a Revenue Cap, this must be returned to customers in the following regulatory term.

The total system over recovery is therefore 0.8 RM (plus interest) and is passed back to electricity customers through a reduction in the average bundled tariff and the relevant components of the average bundled tariff for the next year of the Regulatory Term. If this adjustment occurs in the last year of the regulatory term, then this tariff adjustment will be carried forward to the first year of the next Regulatory Term.

5. Tariff Adjustment Period

Under the proposed revenue cap and actual cost arrangements for the Transmission, System Operation and Single Buyer business entities, the periods of tariff adjustment are as follows:

- ***Transmission revenue cap adjustments***: It is proposed that this adjustment is done on regulatory term basis;
- ***System Operations revenue cap adjustment***: It is proposed that this adjustment is done on regulatory term basis;
- ***Single Buyer Generation actual cost adjustment (for the generation specific tariff component)***: It is proposed that this adjustment is done every six months; and
- ***Single Buyer Operations revenue cap adjustment (for the other operational costs specific tariff component)***: It is proposed that this adjustment is done on regulatory term basis.

It is proposed that these tariff adjustments are done based on audited financial statements. Therefore, there will be a lag of a few months before these tariff adjustments are finalised and implemented. It is therefore proposed that the tariff adjustments are interest adjusted to incorporate the time value of money. The interest rate for calculating the time value of money will be set at an appropriate rate, taking into consideration the length of the lag.

[1] Under the proposed regulatory framework, the generation specific costs of the Single Buyer will be adjusted every six months. The worked example reflects adjustment in regulatory period for simplified illustration of the Revenue Cap and Actual Cost arrangements.

Where forecasts of actual costs or revenues need to be made to make the adjustments, any error made in the forecasts will be compensated for at the next adjustment.

6. Regulatory Term

The Regulatory Term is the period (in number of years) regulated business entities operate under a Price Cap, Revenue Cap, or Hybrid regime with no review of either average set prices or allowable set revenues.

For example, under a Price Cap regime which operates for a five year Regulatory term, the set average price and path does not change with actual sales or actual expenditure (both capital and operating) outcomes. The business entity operates for the Regulatory term under initial Price Cap forecasts. This places strong incentives upon the business entity to seek efficiencies in cost and improve utilisation as it largely retains these efficiencies. The efficiency framework is discussed in Regulatory Guideline Number 3 (RIG 3).

The longer the Regulatory Term the greater the reliance on forecasts and the stronger the incentives for the business. The Regulatory term is set at five years for Transmission and Distribution in UK, Australia and Singapore.

A fixed Regulatory Term also provides certainty of revenue to regulated businesses and generally lowers regulatory and revenue risk (if coupled with the right incentive framework).

6.1 Recommendation on Regulatory Term

The Commission is recommending a Regulatory Term of three (3) years. This is shorter than a five year Regulatory Term applicable in Australia, UK and Singapore, because it is the first time the Regulatory Term concept will be applied in Malaysia. As the Commission gets more comfortable with forecast and cost data it will consider increasing the Regulatory Term to five years.

ANNEX C

REGULATORY IMPLEMENTATION GUIDELINE 3

- RIG 3 -

Sets the revenue requirement principles for each business entity (building block model) & establishes incentive framework: clear principles for treating variances in forecasts (both cost and consumption)

1. Objective

The objectives of RIG 3 are as follows:

- Establish the revenue requirement principles for each of the five TNB business entities[1]; and
- Establish the incentive framework for the five TNB business entities[1].

2. Principles of Revenue Requirement

Revenue requirement in this context is defined as the forecast revenue which each of the five TNB business entities should recover from electricity customers (through electricity tariffs). The revenue requirement should enable the business entity to meet its operational expenditure requirements, invest in new assets, pay relevant taxes and deliver a market based efficient return to investors of the business entities (both debt and equity investors).

The annual revenue requirement for each year of the Regulatory Term must consist of the following:

- ***Forecasts of efficient operating costs***;
- ***A return on the Regulatory Asset Base (RAB)***. The RAB is the average of starting and closing fixed assets. The return on RAB must reflect an efficient market based cost of capital[2];
- ***Forecasts of efficient depreciation***;
- ***Forecast tax payments***; and
- ***An allowance for efficiency carryover amounts***.

The Commission will provide to TNB a Revenue Requirement Model (Model). The Model will describe in detail the data requirements for each of the TNB business entities and the calculation of revenue requirements.

[1] The five TNB business entities are specified in RIG 1.
[2] Cost of capital is further discussed in RIG 4.

3. Revenue Requirement for Customer Services, Transmission, and System Operations

The three business entities of TNB share a common approach to setting their Annual Revenue Requirements (ARR), which is outlined below:

AAR[3] = Return on regulated assets (Return * RAB) + Forecast annual depreciation + Forecast annual operating costs + Forecast annual tax payments + Efficiency carryover amount

The various components of the AAR are discussed below.

3.1 Return on Regulated Assets

The ROA component should deliver an efficient market based return to investors in the business entities. Specifically the ROA is calculated as the forecast market return multiplied by the RAB.

3.1.1 Forecast Market return

The forecast market return is set as the nominal after tax weighted average cost of capital (WACC) and is discussed comprehensively in RIG 4. The formula for determining WACC is listed below:

WACC = (Rf + Dm) * (1 – Tc) * G + (Rf + Be*MRP)*(1-G)

Where

Rf = Risk free rate

Dm = Debt margin

Tc = Tax rate

G = Gearing, measure as Debt / (Debt + Equity)

Be = Equity Beta

MRP = Market risk premium

The WACC parameters are discussed in RIG 4.

[3] Interest payments are not included in the calculation as return to debt providers (or interest) is incorporated in the return or WACC parameter.

3.1.2 Forecast RAB

The RAB for the first year of the Regulatory term is the average of the starting asset value and the closing asset value for that year. There are various options for establishing the starting asset value including historical cost, optimal deprival value and optimised depreciated replacement cost (ODRC). While it is not the intent of RIG 3 to determine which is the most appropriate method to set starting asset values for the TNB business entities, regulators internationally have adopted a range of options including historical cost and an ODRC estimate. For example, the Energy Market Authority (EMA), the electricity regulator in Singapore has adopted historical cost[4]. In particular, the Commission is of the view that land asset values should be based on historical cost or book value, as opposed to any revaluation.

Once the starting asset value is determined, it is intended not to review these starting asset values as it lowers regulatory risk by promoting revenue stability and certainty for the business entities.

The starting asset value includes only fixed assets such as land, plant and equipment, used for supplying electricity to customers (either directly or indirectly). The asset values explicitly do not include other assets such as cash, financial assets, investment in subsidiaries, tax assets intangibles and goodwill. The starting asset values are net of upfront customer contributions or capital received from governments in the form of government grants or subsidies. If electricity customers maintain a customer deposit, then the value of the customer deposit should also be deducted from the starting asset value. This is because customer deposits reduce the capital required by investors. The interest paid on the customer deposits (if any) should be included in the operating cost forecast.

Once the starting asset base is determined, the forecast RAB is set based on the following formula:

RAB = Average of starting asset value and closing asset value

Where;

Closing asset value	**=**	***Starting asset value – annual depreciation + forecast capital expenditure***

Capital expenditure forecasts are in nominal dollars, consistent with the nominal WACC definition. In reviewing capital expenditure forecasts the Commission will test for efficiency and prudency of expenditure forecasts by:

[4] Condition 22, Clause 5 of the Electricity Licence For Transmission Licensee. Electricity Transmission Licence issued by EMA to SP PowerAssets Limited.

- reviewing the efficiency of the underlying asset management, development and replacement policies;
- ensuring consistency between the expenditure forecasts and efficient asset policies; and
- ensuring consistency between capital expenditures and macroeconomic factors including sales and demand growth.

3.2 Depreciation

Annual depreciation will be based on the efficient economic life of assets. In determining the efficient economic life for various asset classes (such as transformers, poles, sub stations, switchgear etc), the Commission will benchmark with other utilities to ensure that the useful life assumptions are consistent with best practice. The Commission will also consider obtaining an independent engineering estimate of useful life for the various asset categories.

Once the useful life estimates are finalised, annual depreciation forecasts will be based on a straight line basis.

3.3 Forecast operating costs

In determining efficient operating cost, the Commission will test for efficiencies through benchmarking (where relevant), a review of historical cost performance and the efficiency and prudency of asset management policies.

Where operating cost forecasts include cost of services procured from related parties[5], these related party costs will only be incorporated in efficient operating cost forecasts if:

- these related party transactions are entered into on an arm's length basis through competitive tendering; or
- these related party costs contain no margin or profit and purely reflect the direct cost of providing these services and the cost is efficient; or
- it can be demonstrated that these related party costs are comparable to market benchmarks (assuming that there are several alternative market service providers for the relevant services).

For Single Buyer Operations, operating cost forecasts should include working capital requirements, which is to be calculated on the basis of the working capital amount multiplied by the Weighted Average Cost of Capital (WACC) (see RIG 4 for the establishment of the WACC). Working capital amounts included in operating expenditure by TNB should be supported with detailed information of debtor and creditor days and amounts. For

[5] The definition of Related Party is as per the Financial Reporting Standard 124 as set by the Malaysian Accounting Standards Board (MASB).

Customer Services operating costs should include the interest payments on customer deposits.

3.4 Forecast tax payments

Annual tax payments will be based on a calculation of forecasts of taxable income and the applicable tax rates. Taxable income will be based on the forecasts of return on assets, operating costs, efficiency carryover amounts and capital allowances.

Capital allowances will be based on the applicable capital allowances rates as per the current and relevant Malaysian Tax Guide. Any tax losses incurred in any year of the Regulatory Term will be carried forward and offset future tax liabilities.

3.5 Efficiency carryover amounts

Efficiency carryover amounts will be determined based on the efficiency carryover scheme. The efficiency carryover scheme operates in addition to the Base Incentives inherent in the proposed regulatory framework. Both the Base Incentives and the efficiency carryover scheme will operate in conjunction with the set Variance Thresholds. Variance Thresholds are discussed in Section 7.1.1.

3.5.1 Base Incentive

The Base Incentives enable the business entities to retain any variances between actual operating and capital expenditure amounts relative to forecasts within the Regulatory term. This will encourage the pursuit of efficiencies in both operating and capital expenditures, as reductions in any expenditure as a result of efficiencies will result in higher return for shareholders. Cost savings should not result in deterioration of network performance or customer service. The business entity will have to provide on an annual basis a comprehensive analysis of the variances between actual expenditure and forecasts. The Commission will consider implementing a network performance and customer service scheme[6], to ensure that deterioration in network and customer service standards result in financial penalties.

The Commission will also consider setting upper and lower variance bands around capital and operating cost variances to ensure the benefits (or the risk) of major cost variances due to forecast errors are not retained by the business entity[7].

[6] To be developed in RIG 6
[7] This is further discussed in Section 7: Incentive Regime

3.5.2 Efficiency carryover scheme

The purpose of the efficiency carryover scheme (ECS) is to provide the business entities a continuous and sustained incentive to pursue cost efficiencies during every year of the Regulatory Term. This is important as under the base incentive regime, the business entities incentive to pursue efficiencies weaken as they approach the end of the Regulatory Term. This is because cost efficiencies will result in a lower cost base for the subsequent Regulatory Term and the time to retain efficiencies during the current Regulatory Term reduces with every passing year of the Regulatory term.

The ECS is designed to provide sustained incentives to pursue efficiencies in operating expenditures. The ECS will operate as follows:

- Towards the end of the Regulatory Term, actual operating expenditure for all years (as per the regulatory accounts[8], except for the last year which will be based on estimates reflecting year to date expenditures) will be compared to the forecast operating expenditure which was adopted to set annual revenue requirement[9].
- The total variance between actual operating expenditure and the regulatory operating expenditure estimates (Cost Efficiency Amount) will be quantified.
- 50% of the Cost Efficiency Amount (Sharing Cost Amount) will be added on to the annual revenue requirement projected for the next Regulatory Term as follows
    - 50% of the Sharing Cost Amount to be added to the first year of the new Regulatory Term
    - 30% of the Sharing Cost Amount to be added to the second year of the new Regulatory Term
    - 20% of the Sharing Cost Amount to be added to the third (and last) year of the new Regulatory Term
- The difference between the actual operating expenditure and the estimated operating expenditure for the last year of the Regulatory term will be taken into account (adjusted for interest) when calculating the Cost Efficiency Amount for the subsequent Regulatory Term.

A worked example is presented below and assumes that cost efficiencies of 20 are achieved every year of the First Regulatory Term.

[8] The framework for developing regulatory accounts is outlined in RIG 10
[9] The setting of revenue requirement is outlined in Section 3 of this RIG

Fig: Example of the ECS (expenditure amounts are in RM)

	First Regulatory Term				Second Regulatory Term		
	Year 1	Year 2	Year 3		Year 1	Year 2	Year 3
Operating expenditure forecast	120	120	120		100	100	100
Actual operating expenditure	100	100					
Estimated operating expenditure			100				
Annual cost efficiency	20	20	20				
Cost Efficiency Amount				60			
Sharing Cost Amount				30			
Efficiency Carryover Amount %					50%	30%	20%
Efficiency Carryover Amount					**15**	**9**	**6**
ARR Operating expenditure forecast	120	120	120		115	109	106

The Efficiency Carryover Amounts are 15 RM for Year 1, 9 RM for Year 2 and 6 RM for Year 3 for the Second Regulatory Term.

The Operating expenditure forecast will reduce from 120 RM to 100 RM for the Second Regulatory Term based on the cost efficiencies achieved. Allowing for the Efficiency Carryover Amounts, the Annual Revenue Requirement (AAR) Operating expenditure forecast reduces from 120 RM to 106 RM by year three of the Second Regulatory Term.

Customers benefit as the total cost has been reduced. The business entity has benefitted from the incentive mechanism as it has firstly retained cost efficiencies in the First Regulatory Term and carried forward 50% of the cost efficiencies to the Second Regulatory Term.

4. Revenue Requirement for Single Buyer

The Single Buyer purchases electricity from the Independent Power Producers (IPPs) based on Power Purchase Agreements (PPPs) and from TNB Generation based on Service Level Agreements (SLAs).

The revenue requirement for the Single Buyer for the Regulatory Term comprises of the following:

- Cost of electricity purchases based on the contractual terms (capacity payments, other fuel and other variable costs) and forecast dispatch (subject to an Actual Cost regime). The Single Buyer Rules, to be developed by the Commission, will set out the detailed requirements for TNB to ensure that its procurement processes and contracts with respect to fuel procurement (and particularly coal) are consistent with principles of economic efficiency. The underlying price of gas and coal will be based on current prices. The Single Buyer will not forecast the price of coal or any proposed adjustments to the future price of gas. The changes to the price of gas and coal will be incorporated in the Imbalance Cost Pass-Through Mechanism as outlined in RIG 8; and
- The ARR calculated based on the methodology as outlined in Section 3 to recover all operational and capital costs of the Single Buyer (subject to a Revenue Cap Regime). The operating costs of the Single Buyer will include an estimate of working capital requirements, which will be calculated based on an assessment of the working capital amount multiplied by the WACC.

5. Converting Revenue Requirement to Average Tariffs

Once the Annual Revenue Requirements (ARR) for the Regulatory Term has been determined, the next step is to set Average Component Tariffs for TNB business entities and an average electricity tariff for electricity customers. The key principle for setting the Average Component Tariffs for the TNB business entities is to ensure that the set tariffs over the Regulatory Term recovers the total ARR over the Regulatory Term on a Net Present Value (NPV) basis.

The total average electricity tariff is the sum of all Component Average Tariffs for each of the TNB business entities. This is shown below:

Total average electricity tariff	***=***	***Customer Services Tariff + Transmission Tariff + System Operations Tariff + Single Buyer Tariff (generation specific tariff + other operating cost specific tariff)***

Presented below is a worked example, where the AAR for a TNB business entity is 100 RM for every year of the Regulatory term, forecast electricity sales (as measured by customer metered sales) is assumed to be 50 kWh growing by 3% per annum, WACC of 8.5% and starting price of 1.8 RM/kWh.

Fig: Example of the setting the average Component Average Tariff for the TNB business entities

		First Regulatory Term		
		Year 1	Year 2	Year 3
Annual Revenue Requirement (RM)		100	100	100
WACC	8.5%			
NPV of ARR (RM)	255			
Forecast electricity sales (kWh)		50	52	53
Starting Price, Po (RM/kWh)	1.80			
Price escalation (X Factor)		4.0%	4.0%	4.0%
Forecast Price (RM/kWh)		1.87	1.95	2.02
Forecast revenue (RM)		94	100	107
NPVof forecast revenue (RM)	255			
NPV difference	0			

In this example, the forecast Component Average Tariff has to increase by 4% per annum to ensure the recovery of the ARR over the Regulatory Term on an NPV basis. This is achieved by setting the Price escalation factor (X Factor) at 4% per annum.

5.1.1 Price control equations

There will be 6 Price Control Equations:

1. The Customer Services Price Control Equation (CS PCQ), which will set the Customer Services Tariff;
2. The Transmission Price Control Equation (T PCQ), which will set the Transmission Tariff;
3. The System Operations Price Control Equation (SO PCQ), which will set the System Operations Tariff;
4. The Single Buyer Generation Price Control Equation (SBG PCQ), which will set the Single Buyer generation specific tariff;
5. The Single Buyer Operations Price Control Equation (SBO PCQ), which will set the Single Buyer other operating cost specific tariff; and
6. The Average Electricity Tariff Price Control Equation (AE TPCQ), which will set the total average electricity tariff and will be a sum of the first four Price Control Equations.

The details of the 6 Price Control Equations and the AE TPCQ will be specified in the Model. The general form of the Price Control Equations is set out below

Customer Services will be subject to a pure Price Cap, in accordance with the following Price Control Equation:

$P_t \quad = \quad P_{t-1} * (1+ X_t)$

Where;

P_t	=	*The price cap in the relevant year*
X	=	*The X Factor, which reflects a pre-determined annual change in prices to meet the revenue requirement (X may be zero to maintain a consistent price level over the Regulatory Term)*
P_{t-1}	=	*P_o, for the first year of the Regulatory Term*

The Transmission business entity, System Operations business entity and the Single Buyer Operations business entity are subject to Revenue Cap regimes. The individual Revenue Cap Equations will be in the following form:

$R_t \quad = \quad R_{t-1} * (1+ X_t) + K_t + K_{t-1}$

Where;

R_t	=	*The revenue requirement in the relevant regulatory term*
X	=	*The X Factor, which reflects a pre-determined annual change in prices to meet the revenue requirement (X may be zero to maintain a consistent price level over the Regulatory Term)*
R_{t-1}	=	*R_o, for the first Regulatory Term*
R_t	=	*Correction for Single Buyer, Transmission and System Operations Revenue Cap adjustments for the previous regulatory term (in the first Regulatory Term, $K_t = 0$)*[10]
K_{t-1}	=	*Correction for forecasting error in Revenue Cap adjustments made in the previous regulatory term (in the first and second Regulatory Term, $K_{t-1} = 0$)*

The adjustment factors for the Revenue Caps will be calculated as follows:

$K_t \quad = \quad R_{t-1} – RE_{t-1;}$ *and*

$K_{t-1} \quad = \quad RE_{t-2} – RA_{t-2}$

Where;

RE_{t-1}	=	*Estimated actual revenue for the previous regulatory term*
RE_{t-2}	=	*Estimated actual revenue for the regulatory term before the previous regulatory term*

[10] The operation of the cost and revenue adjustments are outlined in RIG 2

RA_{t-2} = *Actual revenue for the regulatory term before the previous regulatory term*

Note: *In the first Regulatory Term, $K_t = 0$*
In the first and second Regulatory Term, $K_{t-1} = 0$

6. Tariffs for electricity customers

Electricity tariffs for electricity customers will be set by Customer Services. Customer Services will set electricity tariffs for customer segments (such as domestic, commercial, industrial etc), such that the forecast revenue divided by the forecast electricity sales equals the total average electricity tariff as per the Average Electricity Tariff Price Control Equation.

The annual process of setting electricity tariffs by Customer Services is described in RIG 9.

7. Incentive Regime

In the proposed incentive-based regulatory regime, there are three types of incentives. These are:

7.1 Cost Incentives

The TNB business entities are incentivised to pursue efficiencies in operating and capital expenditures. These incentives have been discussed in Section 3 and comprise of the Base Incentive and the ECS.

To account for significant forecast error, the Commission will set safeguards (or Variance Thresholds) for the first Regulatory Term. Once the Commission gains confidence in the accuracy of forecast data, it will consider removing the Variance Thresholds.

7.1.1 Variance Thresholds

The Variance Threshold will be set at 25% for both operating and capital expenditure. If annual operating or capital expenditure varies by more than 25% of forecasted values, then the ECS will not apply for that year. Furthermore, the Commission will consider adjusting the AAR amounts and the relevant Price Control Equations to correct for forecasting error.

In determining any adjustments to subsequent years AAR amounts, the Commission will take into account any actual cost efficiencies achieved by the TNB business entities.

7.2 Financial incentives

The TNB business entities’ return is based on a benchmark efficient WACC. Therefore if they are able to structure their capital requirements (both debt and equity) such that the actual cost of capital is lower than the regulated WACC, the financial benefit is retained by the business entities.

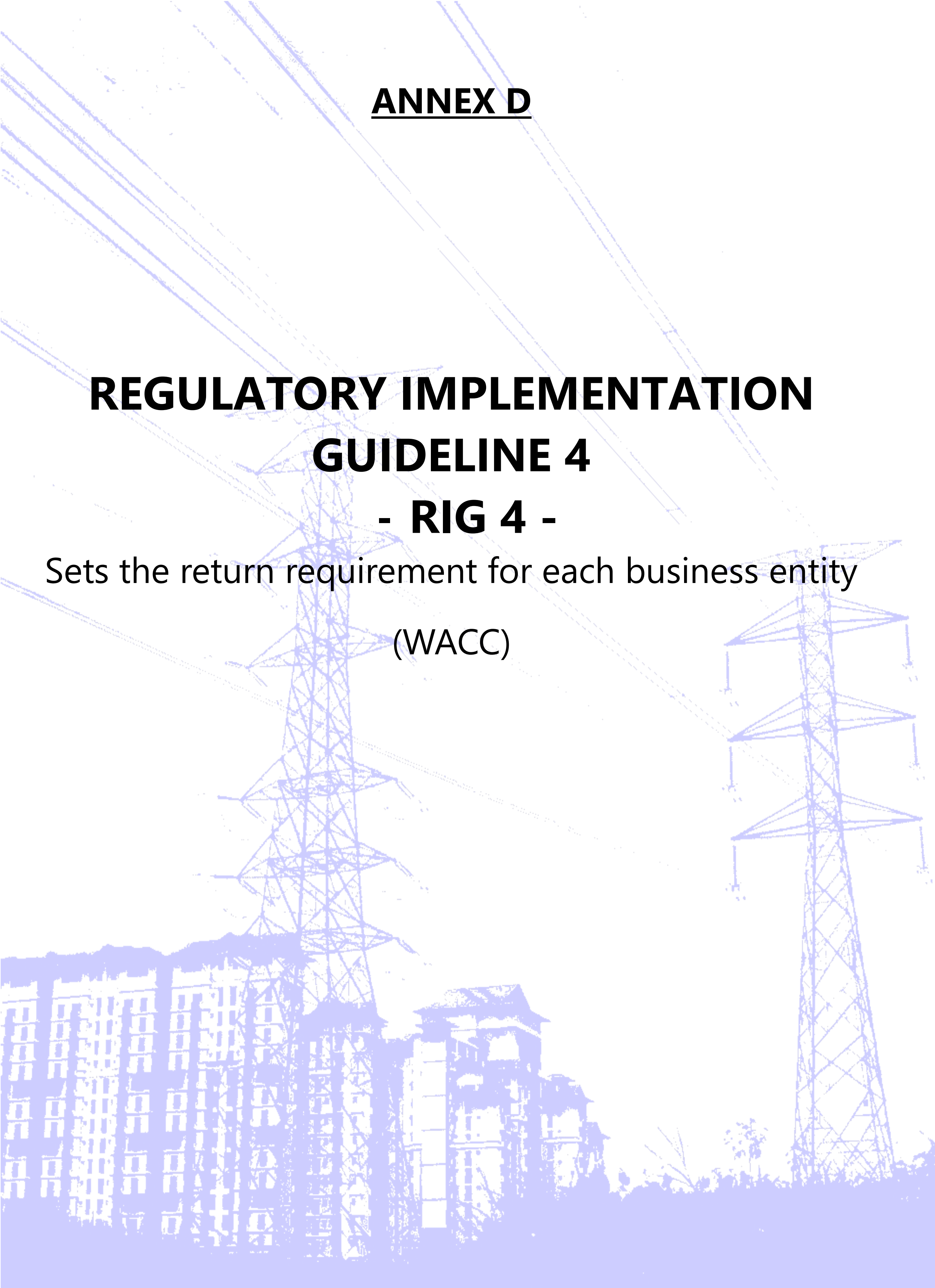
The setting of a regulated return based on an efficient WACC is presented in RIG 4.

7.3 Network performance and customer service incentives

As discussed earlier, savings in operating and capital expenditure should not result in deterioration in network performance or customer service. Therefore, the Commission will consider implementing a network and service performance scheme to incentivise improvements in network performance and customer service.

Under the scheme, the Commission will consider setting targets for both network performance (such as SAIDI, SAIFI for Customer Service and availability for Transmission) and customer services (such as connection time, call centre performance). The TNB business entities will be rewarded for exceeding the targets (by increasing prices to customers) and penalised for not meeting set targets (reducing prices to customers).

This scheme is discussed in RIG 6.



ANNEX D

REGULATORY IMPLEMENTATION GUIDELINE 4

- RIG 4 -

Sets the return requirement for each business entity

(WACC)

1. Objective

The objective of RIG 4 is to outline the guidelines the Commission will adopt in determining the appropriate weighted average cost of capital (WACC) for the TNB business entities.

2. Overview of WACC

Companies finance their investments through a combination of equity and debt. WACC represents the weighted average cost of equity and debt.

In efficient competitive markets, efficient organisations are generally expected (over the long term) to earn a rate of return at least equal to their WACC. If the actual return is too low, a firm will find it difficult to finance investments and may face insolvency or takeover. If the return is too high, then the organisation faces increased competitive threat (where competitors and/or new entrants will over time force returns down to their efficient level).

In non-competitive markets, where prices for services are determined by Government or an industry regulator, prices are set based on delivering an efficient return to the regulated entity. A key element of determining this efficient return in the absence of a market based approach to pricing is to set efficient levels of recoverable expenditure and an efficient, market based cost of capital or WACC.

The Commission will adopt the following principles in determining the appropriate WACC for the TNB business entities.

2.1 Efficiency

The WACC and the WACC parameters must be set on an efficient basis. This implies that the WACC must provide an efficient return to the regulated entities and deliver efficient prices to customers. In ensuring efficiency, the Commission will ensure that the WACC for the TNB business entities:

- is based on an efficient capital structure and credit rating;
- reflects market based returns on debt and equity;
- adequately reflects regulatory and market risk; and
- there is consistency between all the WACC parameters and the underlying cash flows calculated in the determining the ARR for the relevant TNB business entities.

2.2 Market data and trends

In setting the WACC the Commission will ensure (where appropriate) that the analysis is based on Malaysian capital markets (both debt and equity). If data for the Malaysian market is unavailable either due to lack of sufficient history or liquidity, then international market data will be used as a reference point and translated into a Malaysian context.

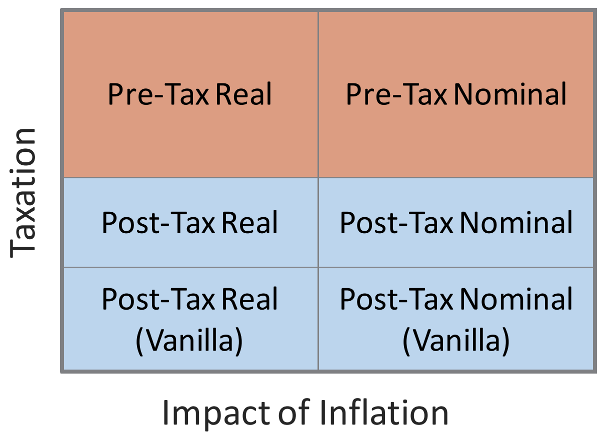
2.3 International best practice

The Commission will consider relevant international regulatory precedence. In particular, regulatory WACC decisions in those countries which have similar incentive based regime as the one proposed for the Malaysian electricity sector, such as Australia, UK, Singapore will be taken into account in the Commissions analysis.

3. WACC definition

Various forms of WACC models exist. In particular, there are numerous models and approaches for deriving the cost of equity component of the WACC. For regulatory purposes, the most common approach to calculating the cost of equity is the Capital Asset Pricing Model (CAPM). Alternative forms of CAPM model exist too. One of the key differences across WACC and CAPM models is the treatment of taxation (i.e. how taxes may affect company and/or investor cash-flows) and inflation. The figure below shows the various model of WACC with different assumptions on inflation and taxation.

Fig: Examples of WACC



All these models are appropriate and with the consistent cashflows will result in similar prices and business NPVs. However, the model choice has implications on complexity of calculation and subsequent adjustment to standard accounting systems and reports. For example, if a real WACC model is adopted, nominal accounting information has to be adjusted to real terms (as accounting information is nominal). Similarly, if an after tax model (post tax) is chosen, tax calculations based on tax accounting need to be conducted and adjustments may be required (if a post tax nominal model is adopted) to exclude the tax shield on interest from the tax calculations.

In recommending the appropriate model for WACC, the Commission notes that TNB, SESB and GMSB have used the nominal post tax WACC model (and CAPM for cost of equity) in their analysis.

The Commission therefore recommends that the post tax (text book) nominal WACC be used to ensure consistency and simplicity and that the capital asset pricing model (CAPM) be used to estimate the cost of equity. Other models to determine cost of equity such as the arbitrage pricing model and forward looking dividend growth models are more controversial (as many more assumptions are required) and less used in regulatory settings.

The Commission recommends the use of the nominal after tax text book WACC definition, as outlined below.

Fig: Nominal after tax WACC

$$WACC = (Rf + Dm) * (1 - Tc) * G + (Rf + Be*MRP)*(1-G)$$

Where

Rf = *Risk free rate*

Dm = *Debt margin*

Tc = *Tax rate*

G = *Gearing, measure as Debt / (Debt + Equity)*

Be = *Equity Beta*

MRP = *Market risk premium*

4. Setting of WACC parameters

This section outlines the approach the Commission will adopt in setting the various WACC parameters.

4.1 Risk free rate (Rf)

The Risk Free Rate represents the return investors require investing in a risk free or close to a risk free asset.
Therefore there are three choices to be made in setting the risk free rate.

- The first is to determine the type of risk free asset;
- The second is to determine the term to maturity of the risk free asset; and
- The third is to determine the exact calculation of the risk free rate, once the risk free asset and the term to maturity are determined.

Defining the risk free asset
As we are determining the WACC in a Malaysian context, the appropriate risk free asset should reflect return investors require to invest in Malaysian Government Securities (MGS). Investing in MGS reflects sovereign risk and will be considered (by investors) the safest underlying and stand alone (without any credit enhancements or credit wraps) investment in Malaysia.

The choice of using the local government bond yield as the risk free rate is consistent with regulatory practice in Australia, UK, Singapore and New Zealand. Although several attempts have been made to determine WACC and indeed risk free rate using a global portfolio, regulators have chosen to stick to the bond yields and market data of their respective countries. Global WACC and consequently global risk free rates and other global parameters are still being discussed with several issues to be resolved such as defining the composition of the global market, the nature and tax status of the marginal global investor, access to the global portfolio, differences in exchange and interest rate setting frameworks etc.

Term to maturity of risk free asset
Establishing the term of the risk free rate is perhaps more controversial. This is because the longer the term, the higher the rate (given a normal upwardly sloping yield curve). Theoretical, the term of the risk free rate should be based on the life of the underlying asset. Generally, jurisdictions opt for a longer duration (say 10+ years), as this is more consistent with the prudent borrowing practices for organisations with long life assets. Regulators in Australia (Australian Energy Regulator) have adopted the yield of a 10 year Australian government bond and the Energy Market Authority (EMA) has chosen the yield on a 20 year Singapore government bond to set risk free rates for determining regulatory WACC.

The Commission's preference is to adopt the yield on the Malaysian Government Securities with term to maturity of between 10 to 20 years as the appropriate risk free rate for setting WACC for the TNB business entities.

Calculating the yield on the risk free asset

The Commission considers it prudent to take a five year historical average of the 10 to 20 year yield on the MGS to set the regulatory WACC. This is because the market for the MGS is not as deep or as liquid as other international benchmarks (such as Australia and UK) and short term market conditions can have a significant impact on current yields.

The Australian Energy Regulator takes a 20 day historical average to set the risk free rate, whilst the UK regulator takes a longer term historical average (5 to 10 years) and also considers current rates.

The Commission will set the risk free rate based on the relevant historical average and current yields on 10 to 20 year MGS at least two months prior to the start of the first Regulatory Term.

4.2 Debt margin (Dm)

In establishing the cost of debt, efficient debt levels (Gearing) and the cost of debt has to be established. The cost of debt is the risk free rate plus the debt margin that an efficient utility would have to pay to finance its debt. In setting the debt margin the Commission has to determine the appropriate efficient credit rating and the term to maturity of the debt portfolio. In general, the debt margin, or the spread above the risk free rate increase as rating deteriorates (reflecting additional default risk) and increased term to maturity (given a normal upward sloping yield curve).

Establishing credit rating

The Commission considers that a utility such as TNB, whose operations have a significant impact on the economy of Malaysia, should be rated at least investment grade. This approach is also consistent with the Australian Energy Regulator (AER), Ofgem (the electricity and gas regulator for Great Britain) and the Energy Market Authority (the regulatory for electricity and gas in Singapore). The AER uses a credit rating of BBB+ (based on S&P credit rating) in setting regulatory WACC, Ofgem does not explicitly adopt a benchmark credit rating but does a financiability test to ensure investment grade financial performance, EMA adopts a benchmark credit rating of A (based on S&P credit rating).

The Commission recommends the setting of an efficient debt margin based on an implied investment grade rating of BBB+ (based on S&P credit ratings). The Commission notes that BBB+ translates to credit rating of AA as determined by RAM Holdings Berhad.

Term to maturity of debt portfolio

The term to maturity of the debt portfolio, should reflect the term of the risk free rate (for consistency in WACC calculations) and be consistent with the long life assets. However noting that the debt portfolio will comprise of both short and long dated bonds and noting the lack of liquidity and depth of long dated corporate debt issues in Malaysia, the Commission recommends that the average maturity of an efficient debt portfolio be set at ten years.

This is consistent with the AER which set debt rate based on the yield of ten year debt, maturity, EMA adopts the yield on 20 year debt, and Ofgem considers the yields on debt maturing up to 20 years.

Calculating debt margin

The Commission recommends that the debt margin (margin above yield of MGS) on ten year corporate bonds with a rating of BBB+ (S&P estimate) or AA (RAM estimate) be set based on a historical five year average. This is consistent with the setting of the risk free rate.

4.3 Gearing (G)

Gearing represents the amount of debt as a percentage of total capital (debt plus equity). In establishing efficient gearing levels, the Commission has considered international practice in Australia, UK, Singapore, and New Zealand all jurisdictions which have implemented WACC based incentive regulation. The AER, EMA and Ofgem have set gearing levels at around 60% to set regulated WACC, consistent with the adoption of investment grade credit rating. The Commission notes the inverse relationship between gearing levels and credit rating which implies a lowering of credit quality with an increase in gearing. The Commission also notes Moody's published research (in 2009) which implies a credit rating of A3 consistent with gearing levels between 60% to 68% for UK utilities. However, given the maturity of the UK incentive regulatory framework, simply adopting such a high gearing to set regulated WACC for Malaysia would be inappropriate (as incentive regulation is yet to formally start in Malaysia).

Therefore the Commission has decided to adopt a somewhat conservative gearing level of 55% to set regulatory WACC for the first Regulatory Term. The Commission will in time as the incentive regulatory framework matures in Malaysia consider raising the gearing level to 60% more in line with efficient international benchmarks.

4.4 Equity beta (Be)

The equity beta is the central element of the CAPM in determining cost of equity and is an indication of the systematic riskiness attached to the returns on ordinary shares. It equates to the asset beta for an ungeared firm, or is adjusted upwards to reflect the extra riskiness of shares in a geared firm, i.e. the Geared Beta or Equity Beta.

To determine the equity beta for a given firm for an efficient capital structure presents many challenges, some of which are discuss briefly below.

- The firm may not be listed and hence no firm specific stock market data exists. In this case, benchmark firms which are listed on the stock market can be used as a proxy. If the firm is listed, the period of beta estimation provides different results.
- Instability of beta estimates. As stock markets are volatile, beta estimates tend to be unstable with extreme market events (like the recent GFC, Asian financial crises and the dot com bubble) impacting stock markets sharply in a short space of time.
- The impact of leverage and taxes. According to most academics, equity beta increases almost linearly with leverage. However, there is often a disconnect between the accepted theoretical behaviour of equity beta and observed beta.
- Convergence to unity. There is some evidence that equity beta converges to one over a long period of time. This is referred to as the Blume Adjustment. The basis of this theory is that as a firm matures, it adjusts its products, markets, gearing and technology and therefore is able to converge to market risk. However, many regulators are now questioning the relevance of the Blume adjustment in determining regulatory WACC. This is because; unlike in competitive markets where firms have choice of products and capital structure, a regulated utility's product offering and capital structure are predefined in setting their regulatory WACC.

Regulators in Australia and UK have spent considerable time and effort on calculating betas for regulated electricity and gas businesses. In Australia, the national regulator AER has recently adopted an equity beta of 0.8, with gearing of 60%. This equity beta of 0.8 has fallen from the previously adopted value of 1, which had been the standard equity beta used by most Australian state regulators since 1994. Most equity beta calculations for UK and American utilities range from 0.8 to 0.5, for a gearing of 60%.

As TNB is listed, the Commission recommends that market data be used to calculated TNB's equity beta. In assessing equity beta estimates the Commission recommends the following:

- at least seven years of historical market data be used to calculate equity beta estimates;
- adjustments should be made to historical data for events like the Global Financial Crises, which have impacted markets significantly over a short period of time;
- the observed equity beta estimates be adjusted to reflect regulated gearing (initially set at 55% for the first Regulatory Term); and
- equity beta estimates be crosschecked with published equity beta estimates for TNB by Bloomberg and other reputable financial market data providers.

As an example, Bloomberg published an equity beta of 0.833 for TNB in December 2009, with a market gearing of 38%. This translated into an equity beta of 1.15 for a market gearing of 55%. The equity beta estimate of 1.15 for TNB is higher than equity beta estimates for regulated utilities in UK and Australia. This is expected, as the regulatory regime is well established in Australia and UK, which has resulted in lowering regulatory risk, resulting in lower cost of equity and equity beta estimates.

The Commission will undertake extensive market analysis and benchmarking and determine estimates of equity beta for TNB consistent with regulatory gearing assumption at least 2 months prior to the commencement of the first Regulatory term.

4.5 Market risk premium (MRP)

MRP represents the premium or extra return investors require to invest in risky assets above the risk free rate. There are two issues here. First the definition of the market and second the calculation of the MRP itself.

Most regulators adopt the stock market index of their respective country as a good proxy for the market. As mentioned earlier, defining a global market presents several challenges and remains a good theoretical concept at best with several issues to be resolved before being accepted a credible metric for regulators to adopt.

Once the market is defined, the methods of calculating MRP are the following

- Historical analysis: Most regulators have tended to adopt a historical calculation of the MRP a good starting point. For a historical analysis to produce a reliable estimate of MRP, typically regulators have required at least 50 years of reliable historical data. This is the most common method of establishing MRP for markets which have the required historical data.
- Sovereign risk assessment: There is a developing theory that equity market risk is influenced strongly by sovereign credit ratings. For example, investors will require a premium to invest in countries which have a lower rating and premiums for lower ratings can be developed based on assumed default rates.

- Forward looking analysis: A dividend growth model based on investor expectations of future market returns can be used to calculate MRP. This method is difficult to implement as several assumptions have to be made regarding investor expectation of long term returns and reliably interpreting analyst forecasts.
- Benchmarking with other markets: Typically more risky markets will tend to have a higher MRP. By comparing markets and their volatilities some assessment can be made for market which either lack historical data or lack coverage by analysts.

For calculating the MRP for Malaysia, the Commission has chosen to rely on various published estimates, benchmarking with other markets and regulatory precedence. Unfortunately there is insufficient historical data to calculate a reliable base estimate of MRP for Malaysia.

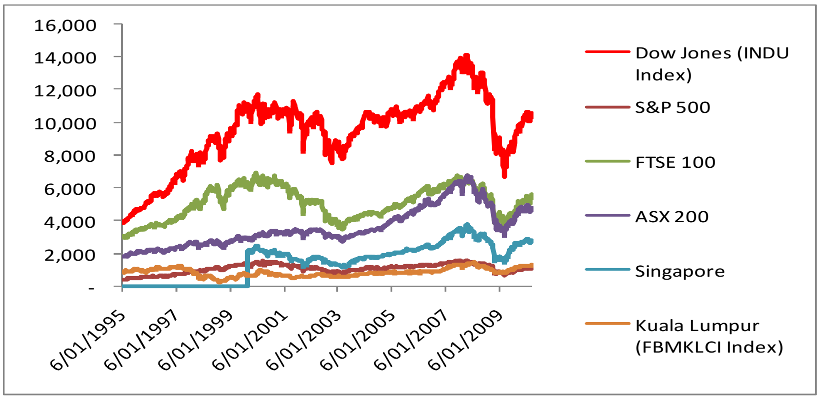
Published estimates of Malaysian MRP: Various reliable estimates of the MRP for Malaysia have been undertaken, with estimates ranging from 7%[1] to 7.63%[2].

Regulatory precedence: International regulatory estimates of the MRP are 6.5% for Australia[3], 7%+ for New Zealand[4], 7% for Singapore[5] and 4.5% for the UK[6]. Most estimates of the MRP are 'backwards looking' as they are based on past differences between market returns and the risk free return. The GFC has caused increased volatility in financial markets, and the MRP has increased as a consequence. Australia recently increased its MRP estimate from 6% to 6.5% as a result of the GFC. New Zealand is similarly considering increasing its (tax adjusted) MRP as a consequence of the GFC[7].

Benchmarking with other markets: The Commission also notes the historical performance of the FBMKLCI 30 with other international and Asian markets. The following figure shows that the FBMKLCI broadly moves in line with other major international indices like the Dow Jones, S&P 500, FTSE 100, ASX 200 and Singapore STI.

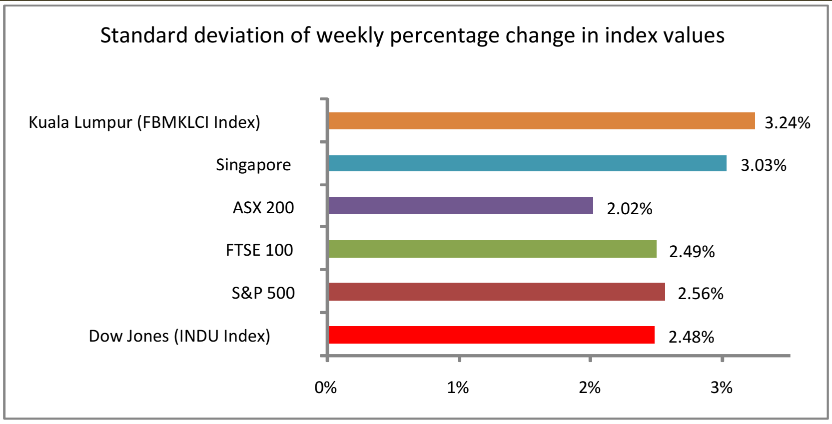
Fig: Market returns for stock market indices

[1] By RHB
[2] By Damodaran. Website is http://pages.stern.nyu.edu/~adamodar/
[3] AER; "Electricity Transmission and Distribution Network Service Providers - Review of the Weighted Average Cost of Capital (WACC) Parameters"; May 2009; p 238
[4] This is a tax adjusted MRP to take into account New Zealand's tax system for dividends (i.e. Brennan-Lally CAPM). It is likely the MRP for New Zealand would be closer to 6.5% if a more conventional CAPM were used.
[5] EMA; *"Review of the Parameters for Setting Vesting Price for the Period 1 January 2010 to 31 December 2010 – Draft Determination";* 9 September 2009; p 10
[6] OFGEM; "Transmission Price Control Review – Documentation on the Financial Model"; October 2006 (Note, OFGEM utilised an Equity Risk Premium (Real) of 4.5% and at the time assumed inflation of 2.6%).
[7] Dr Martin Lally, an advisor to the New Zealand regulator recently stated that the MRP has increased as a consequence of the GFC.



However, the FBMKLCI is more volatile than the major international indices. This suggests that the MRP for Malaysia should be higher than the MRP estimates for Singapore (7%) and Australia (6.5%).

Fig: Volatility of stock market indices



Based on its current benchmarking data and regulatory precedence the Commission's draft recommendation for MRP is 7.5% for the first Regulatory Term. The Commission will review its analysis on MRP and determine a final estimate at least two months prior to the commencement of the first Regulatory Term.

5. Specific WACC estimates for the TNB business entities

The Commission will set the same WACC for all the TNB business entities. The Commission does recognise that the regulatory risk is slightly different for an entity operating under a Price Cap regulatory framework as compared to a Revenue Cap regulatory arrangement. However, this difference is small (and difficult to quantify, given the inherent error in parameter estimation) and mitigated by the ability of Customer Services to adjust its capital expenditure program with sales variations.

The Commission's position is consistent with international regulatory precedence. For example,

- the AER sets the same WACC parameters for both Price Cap and Revenue Cap regulated entities; and
- Ofgem and EMA also adopt the same WACC parameters across all regulated entities (Transmission and Distribution. EMA applies the same WACC for setting regulated vesting contracts for determining generation tariff).

6. Process and timeframe for estimating WACC

In setting the regulatory WACC, the Commission will adhere to the following process:

- TNB to present its WACC estimate based on the principles outlined in RIG 4 eight months before the commencement of the Regulatory Term.
- The Commission will present its draft determination within two months of receiving TNB's proposal. The Commission will allow TNB two months to respond to its draft determination.
- The Commission will present its final determination on regulatory WACC at least two months before the start of the first Regulatory Term.

In summary, the Commission will adopt the following principles for setting regulatory WACC for the first Regulatory Term.

WACC parameter	Key principles	Parameter value
Risk free rate (Rf)	10 to 120 year yield on MGS	Parameter value based on 5 year historical average at the commencement of the First Regulatory Term (adjustments for exceptional market events, like the GFC).
Debt margin (Dm)	Credit rating of BBB+ (S&P estimate) or AA (RAM estimate) Debt portfolio based on 10 year term to maturity.	Based on 5 year historical average (adjustments for exceptional market events, like the GFC).
Gearing (G)	Consistence with maintaining investment grade credit rating (BBB+, S&P estimate or AA, RAM estimate).	Draft determination of 55%.

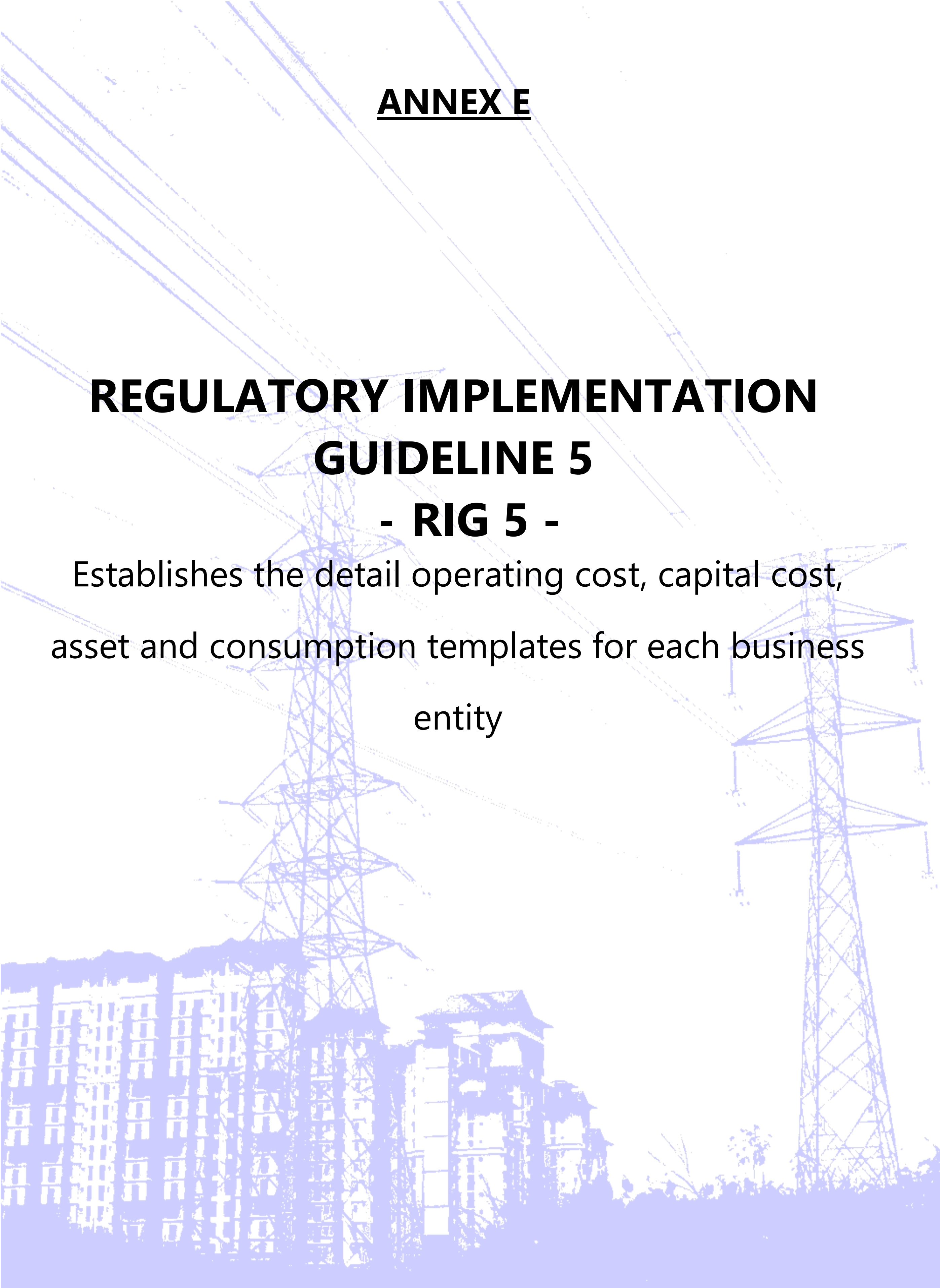
WACC parameter	Key principles	Parameter value
Equity beta (Be)	Market analysis and Benchmarking. Consistent with gearing assumption.	Initial estimate of 1.15. Final determination based on updated market analysis and benchmarking.
Market Risk Premium (MRP)	Benchmarking with other markets. Relevant international regulatory benchmarks.	Draft Determination of 7.5%

ANNEX E

REGULATORY IMPLEMENTATION GUIDELINE 5

- RIG 5 -

Establishes the detail operating cost, capital cost, asset and consumption templates for each business entity



1. Objective

The objective of RIG 5 is to establish detailed operating cost, capital cost, asset and consumption templates for the TNB business entities.

2. Managed Market Model

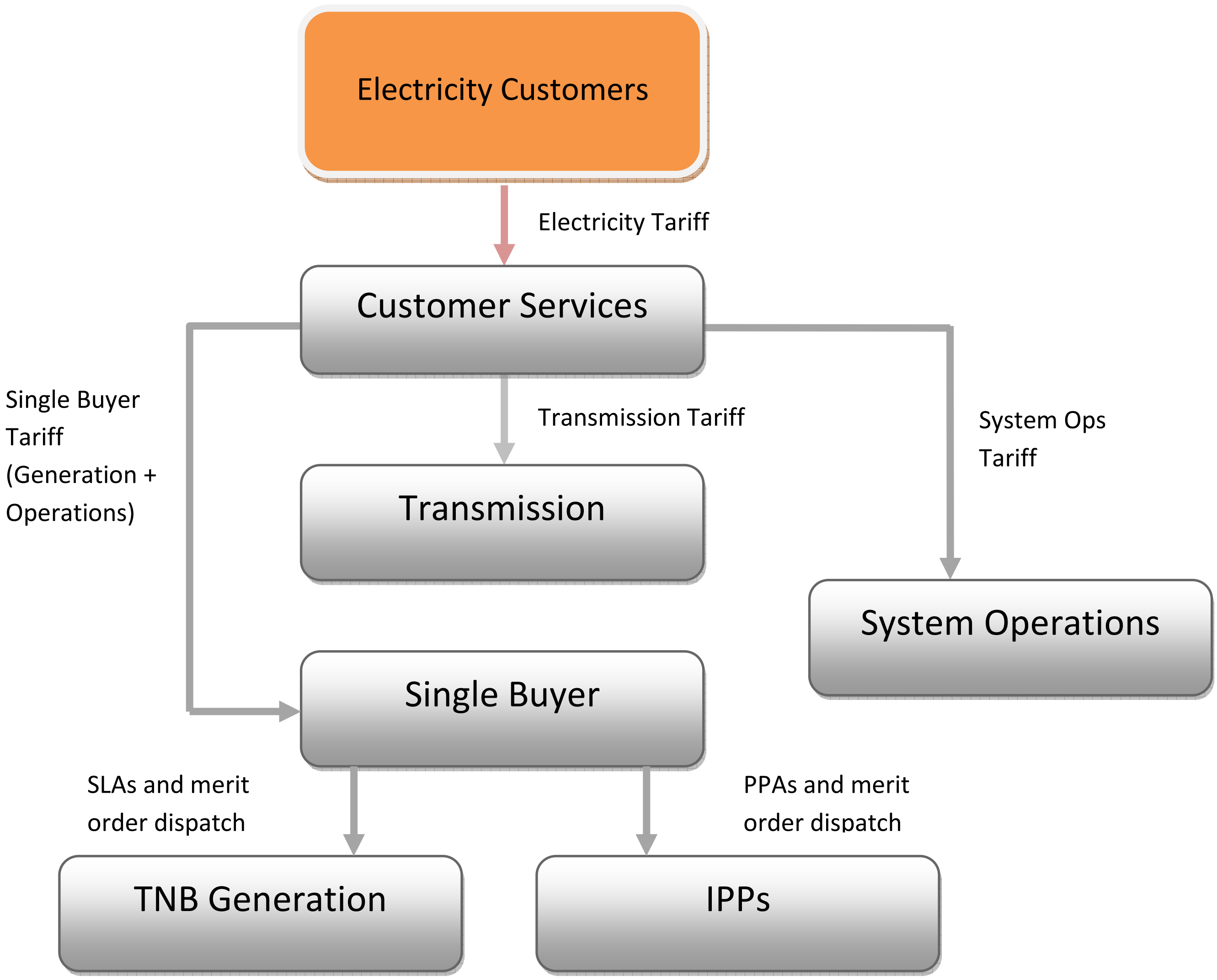
In the Managed Market Model, TNB's business is categorised into five business entities, which are TNB Generation, Single Buyer, Transmission, System Operator and Customer Services. These business entities are defined below:

- Single Buyer: This business entity comprises the functions of the existing TNB's Energy Procurement Division. The main function of the Single Buyer is to procure electricity from IPPs and TNB Generation based on the terms of the PPAs entered into with the IPPs and Service Level Agreements (SLAs) entered into with TNB Generation. The Single Buyer dispatches TNB's generation units and the IPPs based on a dispatch merit order. The dispatch merit order is based on the heat rate, fuel costs and variable operating costs of all the generation plants available (including all IPP's and TNG generation plants) for dispatch. The Single Buyer produces the day-ahead dispatch.
- TNB Generation: This business entity includes the ownership, management and operation of generation plants owned by TNB. TNB Generation contracts with the Single Buyer for the sale of electricity based on Service Level Agreements (SLAs).
- Transmission: This business entity includes the management, maintenance and development of the TNB transmission system for the transmission of electricity to end customers. Transmission system planning is done by the Transmission business entity.
- System Operator: This business entity includes the current functions of transmission system operations of TNB.
- Customer Services: This business entity includes the management, maintenance and development of the distribution system and the sale of electricity to customers.

In addition to the five Business entities of TNB, the IPPs are collectively the sixth business entity, contracting with the Single Buyer for sale of electricity.

The Customer Services business entity charges electricity customers a tariff for the use of electricity. This tariff is a bundled tariff and incorporates a charge for all Generation (IPPs, TNB generation and cost of Single Buyer), Transmission, Transmission System Operations and Customer Services. Customer Services receives all the tariff revenue from electricity customers and subsequently pays the Transmission and the System Operations business entity its share of revenue based on set Transmission Tariffs and tariff for System Operations. The Single Buyer charges a Single Buyer Tariff to the Customer Services business entity, comprising a Generation component (based on forecasts costs of generation determined by the capacity payment in the IPPs and SLAs and all variable generation costs based on the merit order dispatch) and an Operations component (based on the operating costs of managing the operations of the Single Buyer). The Single Buyer receives the Generation Revenue and pays TNB Generation and the IPPs. The flow of funds between the five TNB business entities and the IPPs is shown below[1].

FIG: Flow of funds for Managed Market Model



[1] Regulatory Implementation Guideline 2 (RIG 2) presents in detail the flow of funds between the business entities

The five business entities of Single Buyer, TNB Generation, Transmission, System Operations and Customer Service will be ring fenced with separate accounts.

3. Data Requirement

The tariff setting and regulatory framework for each of the TNB business entities are outlined in RIG 2 and RIG 3.

The Energy Commission (Commission) requires TNB to provide the following data in the prescribed format to enable the implementation of the regulatory and tariff setting framework (as per RIG 2 and RIG 3) for each of the business entities.

The Commission presents an indicative format for costs to be segmented into various cost categories. TNB is required to ensure that costs are presented in sufficient detail and that cost categories reflect broad cost functions. It is also imperative that actual cost data is able to be recorded and presented by the forecast cost categories.

TNB is required to provide feedback on the suggested cost categories for each of the business entities within 15 days of receiving this document. The feedback should outline clearly what cost categories TNB is proposing for each of the business entities. The Commission will consult with TNB before finalising the cost categories.

The Commission’s indicative cost categories for each business entity are present below and are meant to provide a template for TNB to work with and finalise the cost categories.

4. Single Buyer

The aim is to collect data for the operations of the Single Buyer, the energy purchases from the Independent Power Producers (IPPs) and TNB Generation.

4.1. Operations of Single Buyer

The operations of the Single Buyer should include all operating and capital costs required to effectively and efficiently manage all the functions of the Single Buyer to procure electricity from the IPP’s and TNB Generation (Prescribed Services).

In relation to fuel purchases made by the Single Buyer, the TNB will be required to demonstrate that its processes and the contracts entered into are consistent with principles of economic efficiency (particularly in relation to coal fuel procurement). The Single Buyer

Rules will set out the detailed requirements in relation to ensuring that electricity prices only reflect efficient procurement costs.

The format for operating cost and capital cost inputs (and forecast data) is presented in Appendix 1 (Worksheets: Asset inputs and Opex inputs & allocations).

4.2. Single Buyer purchases from IPPs

This cost category includes all costs incurred by the Single Buyer to purchase electricity from the IPPs based on the terms and conditions of the PPAs and the Managed Market Rules[2]. The format for capturing all data, including dispatch, heat rates, fuel costs, capacity payments and variable and fixed O&M is presented in Appendix 1 (Worksheet: Single Buyer Generation inputs).

4.3. Single Buyer purchases from TNB Generation

This cost category includes all costs incurred by the Single Buyer to purchase electricity from the TNB Generators based on the terms and conditions of the Service Level Agreements (SLAs) and the Managed Market Rules. The format for capturing all data, including dispatch, heat rates, fuel costs, capacity payments and variable and fixed O&M is presented in Appendix 1 (Worksheet: Single Buyer Generation inputs). In addition, we recommend TNB provides asset information on each of the TNB generation companies such that we can ensure that the capacity payment delivers an acceptable return. This is because each TNB Generator is a separate company wholly owned by TNB and therefore distortions may be present in the capacity charge (the capacity charges may deliver a return in excess or below the required WACC).

Appendix 1 (Worksheet: TNB Generation inputs) provides a suggested format for all the asset base inputs for TNB Generation. The asset base inputs include asset categories, remaining life, useful life and capital expenditure forecasts for the Regulatory Term. The TNB Generation inputs worksheet in Appendix 1 also incorporates the tax written down values of TNB Generation, capital allowances and capital allowance rates.

4.4. Demand

Appendix 1 (Worksheet: Demand & summary gen costs) provides a summary of the dispatch and cost information contained in the Single Buyer Generation inputs worksheet, and also includes an overall demand input section (with an adjustment for expected losses). The overall demand should match the summary of the dispatch information from TNB Generation and the IPPs, less expected losses.

[2] As mentioned in Regulatory Implementation Guideline 1. The Managed Market Rules need to be developed by the Single Buyer based on the principles outlined in the Grid Code.

TNB should provide supporting documents to demonstrate the reasonableness its demand forecasts, such as historical figures and trends. Expected losses should be supported with loss estimation studies. TNB should also provide details of its loss reduction strategy and forecast cost of achieving loss reductions. The Commission will consider the opening loss levels, submissions from TNB and other stakeholders in its assessment of TNB's proposal.

5. Asset inputs for Transmission, Transmission System Operations, Single Buyer Operations and Customer Services

The indicative format for all the asset related inputs for the Transmission, Transmission System Operations, Single Buyer Operations and Customer Service business entities are presented in Appendix 1 (Worksheet: Asset inputs).

The asset base inputs include asset categories, closing historical asset values for the Base Year, remaining life, useful life and capital expenditure forecasts for the Regulatory Term. TNB is required to provide the asset categories which best represent its asset base and mix of plant and equipment. For example, Transmission asset categories should include at least transmission lines, sub stations, transformers, switchgear and transmission towers. For Customer Services, asset inputs are divided between retail operations and distribution, for which the asset categories should include at least poles, cable and lines, transformers, substations and meters.

The high-level asset inputs in Appendix 1 should also be accompanied by supporting documents which provide a detailed breakdown of assets (for example, list of buildings, plant etc), additions and retirements (if any).

Appendix 1 also incorporates all tax inputs and inputs on any upfront customer contributions or government grants. Asset categories for tax purposes may be less disaggregated if capital allowance rates do not vary between major asset categories.

6. Operating cost inputs for Transmission, Transmission System Operations, Single Buyer Operations and Customer Services

The indicative format for all the operating cost inputs for the Transmission, Transmission System Operations, Single Buyer Operations and Customer Service business entities are presented in Appendix 1 (Worksheet: Opex inputs & allocations).

TNB is required to provide the operating cost categories which best represent the business of Transmission, Transmission System Operations, Single Buyer Operations and Customer

Services. For example, Transmission operating cost categories should include at least staff costs, planned and unplanned maintenance, administration.

For Customer Services, operating cost inputs are divided between retail operations and distribution, for which the operating cost categories should include at least staff costs, planned and unplanned maintenance, meter reading, billing, call centre (customer operations). Customer Services operating costs inputs should also include the interest payments on customer deposits.

For the Single Buyer, working capital is to be presented as an operating expenditure line item. The working capital requirement is to be calculated on the basis of the working capital amount multiplied by the Weighted Average Cost of Capital (WACC) (see RIG 4 for the establishment of the WACC). Working capital amounts included in operating expenditure by TNB should be supported with detailed information of debtor and creditor days and amounts.

7. Joint costs

Joint costs are those costs which are common to all (or at least two) TNB business entities. Joint costs will be separately identified and captured and allocated to the TNB business entities. Examples of joint costs include centralised head office functions like corporate finance, human resources, information technology, legal and other administrative services. Joint costs will be allocated to the business entities based on a cost allocation methodology (primarily based on causal principles). Joint costs may also include assets which are used by more than one business entity, such as the head office building, TNB University etc.

The indicative format for joint costs is presented in Appendix 1 (Worksheet: Joint cost inputs). TNB is requested to review the template and provide suitable cost categories.

7.1 Joint cost allocations

As set out in RIG 7, joint costs incurred by the TNB business entities must be allocated between the relevant business entities on the basis of an approved cost allocation methodology. Appendix 1 (Worksheet: Opex input & cost allocations) includes a cost allocation matrix that specifies the allocation of the joint cost inputs between the Transmission, System Operations, Single Buyer Operations and Customer Services entities.

8. Regulatory reporting

While designing and finalising these data templates, TNB must ensure that it is able to report actual cost data (both asset and operating costs) in exactly the same format as the finalised data templates.

9. Process of finalisation

The Commission will expect TNB's draft response on the data templates 15 working days after it has received RIG 5. The Commission will review the draft data templates as proposed by TNB and issue a draft recommendation within 5 working days for final consultation with TNB.

10. Appendix 1

Appendix 1 is an Excel model and incorporates the following worksheets:

Worksheet	Description
Single Buyer Generation inputs	Data inputs on IPPs, TNB generation. Costs based on IPPs and SLAs. Objective is to calculate all costs of generation (including fuel) which the Single Buyer incurs in procuring electricity.
Demand and summary generation costs	Total demand inputs, including expected losses. Also includes a summary of the generation costs from the Single Buyer Generation inputs sheet.
TNB Generation inputs	Asset base inputs for TNB Generators. The objective is to check if the capacity payments in the SLAs deliver an appropriate return to the respective generators.
Asset inputs	Asset base inputs for Transmission, System Operations, Single Buyer Operations and Customer Services. The objective is to calculate return on asset, return of asset and tax payments in the revenue requirement model.
Opex inputs and allocations	Operating cost inputs for Transmission, System Operations, Single Buyer Operations and Customer Services. Also includes the cost allocation matrix for the allocation of joint costs. The objective is to forecast recovery of efficient operating costs in the revenue requirement model.

Joint cost inputs	This worksheet captures all assets and operating costs which are common to more than one TNB business entity. These joint costs will be allocated to the various TNB business entities based on the cost allocation principles enshrined in RIG 7.

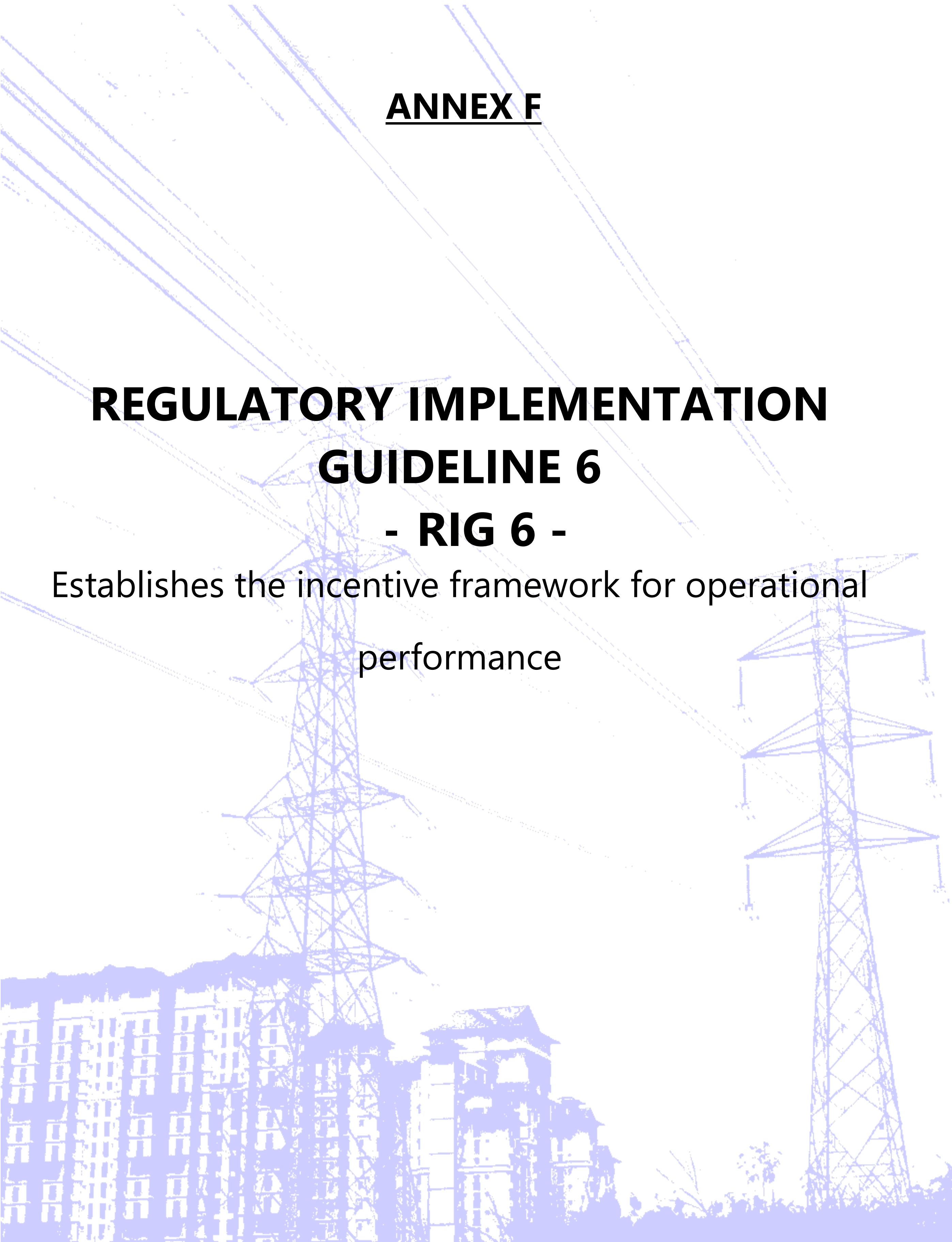
Appendix 1 is part of RIG 5. RIG 5 should be read and analysed in conjunction with Appendix 1.

ANNEX F

REGULATORY IMPLEMENTATION GUIDELINE 6

- RIG 6 -

Establishes the incentive framework for operational performance



1. Objective

The objective of RIG 6 is to provide guidelines to establish an incentive framework for operational performance for the TNB business entities.

2. Background

The Commission has recommended a regulatory framework to determine efficient revenues which the TNB Business entities are able to recover from electricity customers. This regulatory framework is outlined in detail in RIG 2, RIG 3 and RIG 4. In summary the regulatory framework incentivises the TNB business entities to strive for efficiencies in operating and capital expenditures, as business entities retain efficiencies achieved during the current Regulatory Term and carry-forward some operating cost efficiencies to the subsequent Regulatory Term. In addition the regulatory framework places strong incentives to pursue financial efficiencies as the regulated WACC is set based on efficient benchmarks and business entities are able to retain any benefit of lowering their cost of capital below the set regulated WACC.

The Commission considers it prudent and indeed part of its overall design of a holistic incentive-based regulatory system to set standards and incentives to improve operating performance. This is because the Commission does not want cost and financial efficiencies to be achieved at the expense of lowering operational performance.

The Commission considers that operational performance primarily consists of network performance and customer service. Therefore the Commission will consider establishing standards, benchmarks and incentives (and disincentives) for network performance and customer service (where relevant) for the TNB business entities. As part of RIG 6, the Commission will establish the process and guidelines on how it plans to implement the incentive framework for operational performance.

This incentive scheme will work in conjunction with and will not replace all other performance and customer service standards set for TNB (such as meeting set appointment times etc) and any guaranteed minimum service level standards.

3. Finalising operating performance indicators

The first step in designing the incentive scheme for operational performance is to set relevant operating performance indicators for the TNB business entities. The Commission believes that this is perhaps the most important step in the overall design of the scheme. The Commission proposes to adopt the following criteria in setting the operational performance indicators:

- relates closely to the business activities of the TNB business entities;
- highly valued by electricity customers;
- can be objectively measured; and
- can be independently audited.

The Commission proposes that each of the TNB business entities recommend a list of 3 operational performance indicators and demonstrate that they comply with the criteria as outlined above. For example, the Commission notes that:

- system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) are commonly used performance indicators by electricity distribution businesses in Australia, UK and New Zealand and restoration time and power supply interruption events are adopted in Singapore. Call centre performance and losses have been adopted recently by regulators in Australia and UK.
- circuit and plant availability, supply interruption and losses are common indicators adopted for the electricity transmission businesses in Australia, UK and Singapore. In addition power quality indicators (voltage dip incidents) have been used in Singapore for electricity transmission.
- market and system rule compliance and demonstration of efficiency and transparency are key performance indicators adopted for independent system operators and market companies. These may be relevant for the Single Buyer and Transmission System Operator.

The Commission recommends that the TNB business entities take into consideration performance standards set in other international jurisdictions which have implemented incentive-based regulatory frameworks for electricity industries. In addition, the Commission would expect Customer Services to establish performance indicators relevant for both small and large customers.

4. Setting targets

In setting future targets, the Commission will take into consideration, historical performance, the impact of the proposed capital and operational expenditure plans and the inherent variability in performance data.

The Commission can either set a point estimate target for each performance indicator, or an upper bound and a lower bound target for each performance indicator. In the first model, actual performance will be compared to the point estimate target to derive either an incentive or penalty. In the second model, a penalty is applicable if actual performance is less than the lower bound target, an incentive is applicable if actual performance is above the upper bound target and no penalty or incentive is applicable if actual performance lies between the lower and upper bound targets.

The Commission's draft recommendation is to adopt the second model, which sets a lower and upper bound performance target. The Commission will review at least 3 years of historical data in setting both the lower bound and upper bound performance targets.

5. Incentive scheme

The Commission proposes to link the electricity tariffs customers pay to the level of performance expected to be delivered by the respective TNB business entities. Therefore, if the TNB business entities exceed the upper bound performance targets, they should be allowed to charge higher prices. Alternatively, if any of the TNB business entities performance falls below the lower bound performance target they should charge lower prices to customers reflecting a lower grade of service.

Finally, the Commission proposes to set a cap on the maximum penalty or incentive for the TNB business entities. Therefore in addition to setting lower and upper bound values for each parameter, the Commission will need to set targets for upper bound cap and lower bound cap for each performance indicator.

The Commission notes that the AER[1] has capped both the incentive and penalty for Victorian electricity distribution businesses at 5% of total distribution revenues and about 2% of total transmission revenues for the Victorian electricity transmission business. Similarly Ofgem[2] has capped both the incentive and penalty at about 97 bps for distribution

[1] AER, Final decision SP AusNet transmission determination, January 2008, page 185. AER, Final decision, Victorian electricity distribution network service providers, Distribution determination 2011–2015, October 2010, page 739

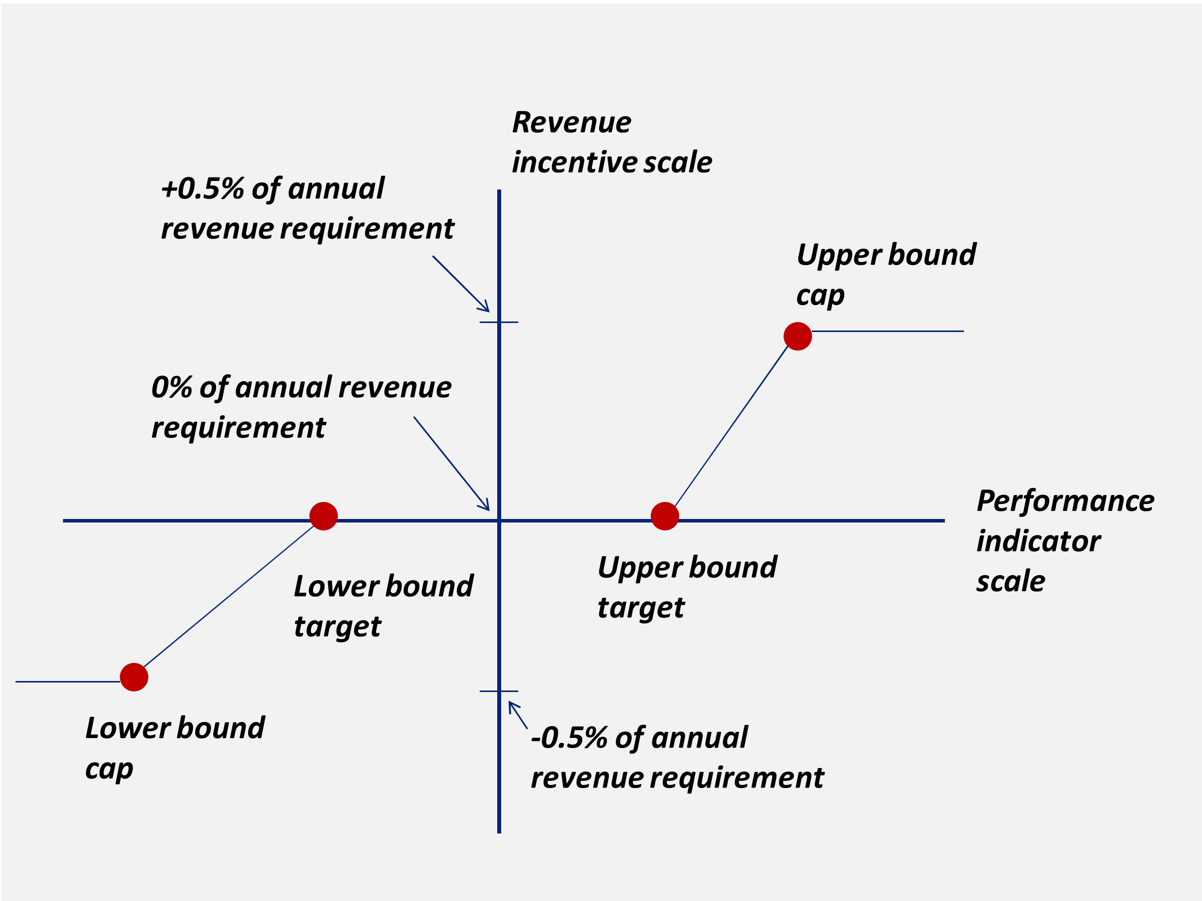
[2] Ofgem, Electricity Distribution Price Control Review, Final Proposals, 7 December 2009, page 16, 17

businesses to manage an efficient level of network losses and 42 bps for several customer satisfaction indicators.

The Commission proposes to cap the annual financial exposure to the TNB business entities at 0.5% of annual revenue requirement for the first Regulatory Term as determined in accordance with RIG 3. In determining this cap, the Commission has taken into consideration that incentive regulation is relatively new in Malaysia and therefore a soft start is recommended. As the Commission and the TNB business entities get more experience with implementing incentive-based regulation, the cap can be increased and be gradually brought in line with international benchmarks.

The proposed incentive scheme is illustrated below.

FIG: Proposed incentive scheme



As shown above, if actual performance is within the Upper and Lower bound targets, there is no incentive or penalty. If actual performance is below the Lower bound target, the penalty starts and caps out at 0.5% of annual revenue requirement when actual performance reaches (and exceeds) the Lower bound cap value. Conversely, if actual performance is better than the upper bound target value, the incentive commences and caps out at 0.5% of annual revenue requirement when actual performance reaches or exceeds the Upper bound cap value.

The revenue incentive or penalty amounts for actual performance between the upper and lower bound target values and their respective cap values will be based on a straight line linear equation.

A worked example is provided below for illustration. Consider the following operational performance scheme, which comprises of SAIDI and SAIFI targets with annual revenue requirement of RM 100 million and total incentive cap of 0.5% of revenue requirement.

FIG: Incentive scheme worked example

	SAIDI (in minutes)	SAIFI
Upper bound cap	5	1.5
Upper bound target	10	2
Lower bound target	15	2.5
Lower bound cap	20	3
Actual performance	***7***	***1.6***

SAIDI incentive: 0.15% * 100 = RM 0.15 million.

Where, 0.15% is calculated based on slope equation[3] with SAIDI upper bound cap representing 0.25% revenue incentive and SAIDI upper bound target representing 0% revenue incentive.

Y = -0.005 * X + 0.005
X = Actual SAIDI of 7

SAIFI incentive: 0.20% * 100 = RM 0.20 million.

Where, 0.20% is calculated based on slope equation with SAIFI upper bound cap representing 0.25% revenue incentive and SAIFI upper bound target representing 0% revenue incentive.

Y = -0.05 * X + 0.01
X = Actual SAIFI of 1.6

[3] The slope equations are based on straight linear regression. The slope equation will vary with upper / lower bound cap and upper / lower bound values.

6. Implementation process

The Commission proposes the following implementation plan.

- The TNB business entities propose a draft set of 3 performance indicators along with the lower bound, upper bound and their respective cap values within 2 months of the finalisation of RIG 6, which best meet the criteria specified in section 3 of RIG 6. Included in the TNB business entities proposal will be at least 3 years of historical data and the basis and process of calculating the parameter values. The Commission will review the proposal of the TNB business entities and provide its draft determination within 2 months. The Commission will then consult with the TNB business entities and other stakeholders as required and finalise the 3 performance indicators within 1 month from the date of issuance of its draft determination.

- The Commission will not adjust electricity tariffs annually during the first regulatory period. Instead, the Commission recommends that the incentive or penalty amounts be calculated for every year and the accumulated total for the first Regulatory Term be amortised and included as part of revenue requirement over the subsequent Regulatory Term. This will ensure that electricity tariffs are not impacted for the first Regulatory Term while still retaining the incentive to improve and maintain operational performance. The Commission will consider doing annual adjustments to electricity tariffs within a Regulatory Term later.

- For the first regulatory period, no incentive or penalty amounts will be implemented as practice in UK and Australia when the IBR regime started. Once the Commission gets more experience in administrating the scheme and setting targets it will consider implementing the incentive or penalty scheme in the subsequent regulatory period.

ANNEX G

REGULATORY IMPLEMENTATION GUIDELINE 7

- RIG 7 -

Establishes the cost allocation principles (to allocate common costs)

1. Objective

The objective of RIG 7 is to provide guidelines to establish cost allocation principles for allocating joint costs incurred by TNB in supplying electricity to customers in Malaysia between the various TNB business entities.

2. Background

The costs that a regulated entity incurs in the provision of regulated services can be broadly categorised into either direct costs or joint costs.

2.1 Direct costs

Direct costs are costs incurred by a regulated entity for business activities that are required solely for providing regulated services applicable for that specific regulated entity. Direct costs incurred by the relevant regulated entity are ring fenced from other activities of the corporate group that the regulated entity belong to and are recorded and captured directly in an account category which belongs solely to the relevant regulated entity.

For example, costs incurred for meter reading activities typically are direct costs for a regulated distribution business entity and are recorded and captured directly in the ring fenced accounts which belong solely to that relevant regulated entity.

2.2 Joint costs

Joint costs are costs which relate to certain business activities that are performed centrally by the corporate group for more than one regulated entity or a combination of regulated and non-regulated business entities. Centralisation of certain corporate functions such as corporate IT and Treasury makes business sense as these functions are common to all business entities (both regulated and non-regulated) of the corporate group and therefore centralisation of the function is often the most efficient business delivery model.

These joint costs have to be allocated to the relevant regulated business entities to enable regulated cost recovery from electricity customers via regulated electricity tariffs. Before the joint cost allocation process, the regulated entity must demonstrate that these joint costs are incurred to provide regulated services and therefore need to be recovered through regulated tariffs. Once that is established, robust joint cost allocation rules need to be developed to ensure that the costs allocated to regulated entities are efficient and recoverable through regulated pricing.

RIG 7 presents the principles that the Commission has established for TNB to follow in allocating joint costs to its various regulated business entities. For clarification, costs as implied in this guideline include both operating costs and capital expenditure.

3. Key principles for allocating joint costs

The Commission has established the following key principles for developing a robust cost allocation methodology to allocate joint costs.

- Only those joint costs are to be allocated to regulated business entities which are incurred in the provision of regulated services for the respective regulated entities.
- Only efficient joint costs will be allocated to regulated entities.
- A particular joint cost can only be allocated once.
- The regulated entity must clearly specify how joint costs are allocated and the basis for allocation (cost allocation methodology).
- A stand alone basis for allocating joint costs is not acceptable. The sum of allocated joint costs must not exceed the total value of the joint costs.
- The basis of allocating joint costs, once approved by the Commission must be reflected in the preparation of the regulatory accounts and must not be changed during the course of the Regulatory Term.

4. Implementation

This section outlines the Commission's preferred approach on the implementation of the allocation of joint costs based on the principles as specified in Section 3 of this guideline.

4.1 Cost allocation methodology

The Commission will expect the relevant TNB business entities to propose a detailed cost allocation methodology, consistent with the cost allocation principles. The cost allocation methodology should incorporate at least the following items:

- A clear presentation of the structure of the parent company, with a complete listing of both regulated and non regulated business entities.
- A clear explanation of all joint costs and justification on how these costs are relevant to the provision of electricity to customers connected to the TNB electricity network in Malaysia.
- Detailed justification of the basis adopted to allocate joint costs to the various business entities. The Commission expects that a causal basis be adopted to allocate most joint

costs. If a causal basis to allocate joint costs is not applicable, then the rational for departure from a causal basis must be clearly explained.

- Demonstration that the sum of all allocated costs is not greater than the total joint costs.
- A clear explanation on how the proposed joint cost allocation will be implemented in the financial and management accounting systems. The business entities must be able to allocate actual joint costs incurred based on the proposed cost allocation methodology in an efficient and timely manner.
- The Commission will review and approve the cost allocation methodology within 2 months of receiving the cost allocation methodology.
- The cost allocation methodology, once approved will not change during the Regulatory Term.
- Any changes to the approved cost allocation methodology for subsequent Regulatory Terms must be approved by the Commission.

4.2 Regulatory accounts

The Commission will expect the Regulatory Accounts for the TNB business entities to be based on the approved cost allocation methodology. The Commission will require the following:

- A statement from the auditors of the TNB business entities confirming that the regulatory accounts are consistent with the approved cost allocation methodology.
- Any inconsistencies found by the auditors between the proposed regulatory accounts and the cost allocation methodology must be highlighted along with the reasons for non compliance signed off by senior management of the TNB business entities.

In conducting the audit of the regulatory accounts, the Commission does not expect the auditors to comment on the cost allocation basis which underpins the approved cost allocation methodology. The auditors are to focus only on compliance with the cost allocation methodology.

4.3 Forecasts

As per RIG 3, the Commission will determine annual revenue requirement for each of the TNB business entities based on efficient forecasts of costs. Therefore, in determining the revenue requirement, the Commission will ensure that forecasts of joint costs are allocated based on the approved cost allocation methodology.

ANNEX H

REGULATORY IMPLEMENTATION GUIDELINE 8

- RIG 8 -

Establishes the imbalance cost pass through mechanism

1. Objective

The objective of RIG 8 is to provide guidelines to establish an Imbalance Cost Pass-Through mechanism to enable the recovery of actual fuel related and other generation specific costs.

2. Background

The Single Buyer procures the required electricity generation (to meet customer demand) from IPPs and TNB generation based on Power Purchase Agreements (PPAs) and Service Level Agreements (SLAs) respectively. This Managed Market Model is specified in RIG 1. The Single Buyer charges a Single Buyer Tariff based on forecasts of electricity generation costs and all other operating costs which it incurs for the Regulatory Term. The Single Buyer Tariff comprises of two elements:

- ***the Single Buyer Generation tariff component***, which is based on all costs of generation including fuel, capacity payments and other costs associated with the terms and conditions of the PPAs, SLAs and other fuel procurement contracts; and
- ***the Single Buyer Operations tariff component,*** which is based on the other operational and capital related costs of running the Single Buyer operations and includes an allocation of joint costs (if any).

For the generation specific tariff component, the Single Buyer operates under an Actual Cost regime as specified under RIG 2. The Actual Cost regime implies that the Single Buyer is able to recover its actual costs of procuring electricity from the IPPs and TNB Generation from electricity customers. The actual cost of procuring electricity from the IPPs and TNB Generation comprises:

- all costs incurred by the Single Buyer under the PPAs and the SLAs, such as capacity payments, fuel costs, incentive or bonus payments etc; and
- all costs incurred for the procurement of coal and gas under various coal and gas supply contracts by the Fuel Procurement Division (FPD) of TNB.

As per RIG 2, the actual revenue earned by the Single Buyer based on the generation specific tariff component of its total Single Buyer Tariff is compared to the actual cost of electricity procurement for every six month period and variances (including the time value of money) adjusted for in subsequent six month periods.

The actual cost incurred for the procurement of electricity generation by the Single Buyer will be different to its actual revenue received from the generation specific component of the Single Buyer Tariff, as it is based on forecasts costs which will be different to actual cost due to:

- variances between actual customer demand and forecast demand;
- variances between actual gas and coal prices and forecast prices;
- variances between forecast plant mix and actual dispatch; and
- variances between actual payments (and receipts from liquidated damages and withholding of capacity payments etc) from other terms and conditions of the various contracts, including the PPAs, SLAs and fuel procurement contracts from those included in the forecasts.

Every 6 months, commencing the start of the first regulatory term, the Single Buyer will compare its actual cost of electricity procurement to the actual revenue it receives based on the generation specific component of the Single Buyer Tariff. Any variances, either positive or negative, will be passed on to electricity customers via an adjustment in their final electricity tariffs. This tariff adjustment process is termed the Imbalance Cost Pass-Through Mechanism (ICPTM) and is outlined below.

3. Implementation

This section outlines the Commission's preferred approach on the implementation of the Imbalance Cost Pass-Through Mechanism. The key steps as outlined below include the six monthly adjustments for gas and coal prices, preparation of a six monthly fuel cost report and the proposed tariff approval process.

In summary there are two adjustments as part of the Imbalance Cost Pass-Through Mechanism.

- The first is to adjust for the impact of any known changes in gas and coal prices, the Fuel Price Adjustment.
- The second is an overall adjustment, The Fuel Cost Adjustment and Other Generation Specific Cost Adjustment which ensures that the Single Buyer's actual revenue based on its generation specific tariff component equals its actual cost of generation procured from TNB generation and IPPs

3.1 Fuel Price Adjustment

As outlined in RIG 3, the Single Buyer in forecasting its generation costs will use the current price of gas and coal. Therefore changes to gas and coal prices will impact the profitability (and viability) of the Single Buyer if corresponding changes are not incorporated in the generation specific tariff.

The Commission will expect the Single Buyer to submit a detailed fuel cost report for every six month period of the Regulatory Term no later than 21 days before the expiry of the relevant six month period based on actual 5 month and estimated for month 6. This fuel cost report will present the changes in fuel cost as a result of changes in fuel prices, unit sales and generation mix from the assume figures at the time the regulatory period and Base Tariff was established. The purpose of this report is to analyse the impact of all those changes to the total generation specific tariff component.

Changes in fuel price

The Single Buyer will present detailed analysis and documentation supporting and verifying the changes to both gas and coal prices for the period. The documentation should include

- Government mandated changes to gas prices; and
- Pricing data for coal consistent with current coal contracts.

Adjustment Formula for Fuel Cost and Other Generation Specific Cost

The Single Buyer will present the impact of changes in gas and coal prices and Other Generation Specific Cost on the generation specific tariff component. This adjustment will be based on (i) Fuel Price Adjustment Formula and, (ii) Other Generation Specific Cost Adjustment Formula. These formulas will determine the Generation Specific Tariff Component for the Single Buyer for the following 6 month period.

Fuel Price Adjustment formula

This formula is to capture the variation in fuel cost as a result of changes in the fuel price, generation mix, foreign exchange etc. from the figure used to establish Single Buyer Tariff.

FCPT	**FCPT 1 ± PCPT 2**
FCPT 1	(EAFC - FFC)t-1/EAUSt-1 (Fuel cost Pass-Through for the period t-1 base on estimated actual fuel cost)
EAFC	Estimated Actual Fuel Cost based on 5 month actual and 1 month forecast
FFC	Initial Forecast of Fuel Cost based on assumed quantity and price at the beginning of Regulatory Period and Base Tariff is set.
EAUS	Estimated Actual Unit Sale
FCPT 2	$[((FCPT_{t-1} * FUS_{t-1}) - AFC_{t-2})]/AUS_{t-2}$ Adjustment for over or under recovery of actual fuel cost (Audited) for period t-2 and the Fuel Cost Pass-Through collected in period t-1.
FUS	Forecast Unit Sold
AFC	Audited Fuel Cost
AUS	Audited Unit Sold

Other Generation Specific Cost Adjustment formula

This formula is to capture the variation in Other Generation Specific Cost as a result of changes in, generation mix, foreign exchange etc., capacity payment, renewable energy, distillate cost etc from the figures assumed at the time the Single Buyer Tariff was established.

GSCPT	**GSCPT 1 ± GSCPT 2**
GSCPT 1	$(EAGSC - FGSC)_{t-1}/EAUS_{t-1}$ (Adjustment for variation in Other Generation Specific Cost)
EAGSC	Estimated Actual Other Generation Specific Cost base on 5 month actual and 1 month forecast
FGSC	Initial Forecast of Other Generation Specific Cost
EAUS	Estimated Actual Unit Sale
GSCPT 2	$[((GSCPT_{t-1} * FUS_{t-1}) - AGSC_{t-2})]/AUS_{t-2}$ Adjustment for under or over recovery of variation in Other Generation Specific Cost based on Audited and Estimated Actual figures
FUS	Forecast Unit Sold
AGFC	Audited Other Generation Specific Cost
AUS	Audited Unit Sold

Proposed tariff adjustment

The Commission proposes that any adjustments to the Single Buyer generation tariff to account for any Fuel Cost Adjustment (FCPT 1) and Other Generation Specific Cost Adjustment (GSCPT 1) be implemented immediately in the following 6 month period based on actual 5 month and estimated 1 month figures. The Commission will require the ***Estimated Actual Fuel Cost and Generation Specific Cost report from Single Buyer*** on the first week of month 6 of the relevant 6 month period. The Commission will approve the FCPT 1 before the end of month 6 so that it can be implemented in the following 6 month period.

Any ***over or under recovery*** of Fuel Cost Adjustment (FCPT 2) and Generation Specific Cost Adjustment (GSCPT 2) from the audited actual figure will be adjusted accordingly in the subsequent 6 month period.

Audit requirement

The Commission will require the Fuel Cost and Other Generation Specific Cost report and the application of the Fuel Price Adjustment and Other Generation Specific Cost Adjustment prepared by the Single Buyer to be certified as correct by a reputable audit company.

Worked example

The following worked example shows how changes to the gas commodity price and/or changes to the coal commodity price will flow through to changes in the Fuel component and Generation Specific Tariff component of the Single Buyer. In the example:

- The initial Single Buyer Base Tariff is 24.61 sen/kWh;
- In the first 6 month period of the Regulatory Year, the fuel cost has increased by 5.32 sen/kWh from 12.94 sen/kWh to 18.26 sen/kWh as a result of changes in [*gas price from RM 10.7/mmBtu to RM 16.7/mmBtu and coal price from USD85/tonne to USD110/tonne*] respectively. This increase will be pass-through in the second six (6) month period (FCPT 1);
- In the first six month period of the Regulatory Year, the Other Generation Specific Cost has increased by [RM278.67 million or 0.58 sen/kWh]. This increase will be pass-through in the following six month period (GSCPT 1); and
- Any over or under recovery of the collected FCPT1 and GSCPT 1 from the Audited Actual Fuel and Other Generation Specific Costs will be adjusted accordingly in the subsequent six month period (FCPT 2 and GSCPT 2).

***Fig: Example of the fuel price adjustment* (FCPT1)**

	First Regulatory Year		Second Regulatory Year	
	1st. 6 month	**2nd. 6 month**	**1st. 6 month**	**2nd. 6 month**
Estimated Actual Fuel Cost for each period (To be calculated on month 6, based on 5 month actual and 1 month forecast) - [For illustration purpose the actual gas price is RM16.7/mmbtu, Coal USD 110/Tonne and RM/USD - 3.12]				
$EAFC_g$ (Estimated actual gas cost based on generation mix and price)	4,409.89	4,409.89	4,653.41	4,653.41
EAFCc (Estimated actual coal cost based on generation mix and price)	4,658.40	4,658.40	4,854.78	4,854.78
EAFC (Total estimated actual fuel cost)	9,068.30	9,068.30	9,508.19	9,508.19
EAUS (GWh) - Estimated Actual Unit Sold	49,665.78	49,665.78	50,947.63	53,027.12
Actual Fuel cost component (sen/kwh)	18.26	18.26	18.66	17.93
Original Forecast of Fuel Cost for each period derive based on assumed generation mix, fuel price and unit sold at the time the Base Tariff was established i.e gas at RM10.7/mmbtu, Coal at USD85/tonne and RM/USD = 3.12				
FFC_g (Forecast gas cost based on assume generation mix and price)	2,825.50	2,825.50	2,981.53	2,981.53
FFCc (Forecast coal cost based on assume generation mix and price)	3,599.68	3,599.68	3,751.42	3,751.42
FFC (Forecast Fuel Cost)	6,425.18	6,425.18	6,732.95	6,732.95
Sale Forecast (Gwh)	49,665.78	49,665.78	50,947.63	53,027.12
Forecast Fuel Cost component (sen/kWh)	12.94	12.94	13.22	12.70
Fuel cost Variation	2,643.12	2,643.12	2,775.24	2,775.24
Fuel cost Variation (Sen/kWh) - (To be Pass-Through in the following 6 month period)	5.32	5.32	5.45	5.23
FCPT 1		**5.32**	**5.32**	**5.45**

Fig: Example of the fuel price adjustment **(FCPT2)**

	First Regulatory Year		Second Regulatory Year	
	1st. 6 month	**2nd. 6 month**	**1st. 6 month**	**2nd. 6 month**
Approved FCPT1 (sen/kWh)	**-**	**5.32**	**5.32**	**5.45**
EAUS (GWh) - Estimated Actual Unit Sold		49,665.78	50,947.63	53,027.12
Total FCPT 1 Collection		2,643.12	2,711.34	2,888.52
Audited Actual Fuel Cost Variation (Available at the end of 2nd six month period)	2,510.96	2,510.96	2,636.48	2,636.48
Audited Actual Unit Sold (Available at the end of 2nd 6 month period)	49,665.78	49,665.78	50,947.63	53,027.12
(Over)/Under recovery of Fuel Cost Variation			(132.16)	(200.37)
FCPT 2 (Over)/Under recovery of Fuel Cost Variation (sen/kWh)	-	-	(0.27)	(0.40)
FCPT = FCPT 1+FCPT 2		5.32	5.06	5.04

Fig: Example of Other Generation Specific Cost adjustment **(GSCPT)**

	First Regulatory Year		Second Regulatory Year	
	1st. 6 month	2nd. 6 month	1st. 6 month	2nd. 6 month
EASGC (Estimated Actual Other Generation Specific Cost)	5,852.13	6,062.06	6,062.06	6,077.75
FSGC (Forecast Other Generation Specific Cost)	5,573.46	5,773.39	5,773.39	5,788.33
Increase /(Decrease) in Other Generation Specific Cost	278.67	288.67	288.67	289.42
EAUS (GWh) - Estimated Actual Unit Sold	49,665.78	49,665.78	50,947.63	53,027.12
Increase /(Decrease) in Other GenerationSpecific Cost (sen/kWh)	0.561	0.581	0.567	0.546
SGCPT 1 (Other Generation Specific Cost Pass-Through)		0.561	0.581	0.567
Collection for Variation in Other Generation Specific Cost		278.67	296.12	300.45
Audited Actual Other Generation Specific Cost (Available at the end of 2nd 6 month period)	5,910.66	6,122.68	6,122.68	6,138.53
Audited Actual Unit Sold (Available at the end of 2nd 6 month period)	49,665.78	49,665.78	50,947.63	53,027.12
Under/(Over) Recovery of Variation in Other Generation Specific Cost			58.52	53.17
SGCPT 2 - Under/(over) Recovery of Other Generation Specific Cost (Sen/kWh)			0.12	0.10
SGCPT - (Total Other Generation Specific Cost Pass-Through)		0.56	0.70	0.67
Single Buyer Base Tariff [??]	21.53	24.63	24.63	24.63
FCPT 1		5.32	5.32	5.45
FCPT 2		-	(0.27)	(0.40)
SGCPT 1		0.56	0.58	0.57
SGCPT 2		-	0.12	0.10
Total Single Buyer tariff		30.51	30.38	30.34
Single Buyer Total Revenue		**15,153.27**	**15,479.09**	**16,089.67**
Single Buyer Total Generation Specific Cost		**15,190.98**	**15,630.88**	**15,646.72**
		(37.71)	**(151.79)**	**442.95**

3.2 Fuel cost and Other Generation Specific Cost adjustment

The Commission will expect the Single Buyer to submit the following:-

- Detailed Estimated Actual Generation cost report for the current six month period of the Regulatory Term based on 5 month actual figure and 1 month estimated figure no later than first week of month 6 of the relevant six month period. This generation cost report will present (i) detailed calculation of the estimated actual Fuel Cost and Other Generation Specific Cost incurred by the Single Buyer under the PPAs and the SLAs such as capacity payments, fuel costs, incentives or bonus payment etc.. (ii) all costs incurred for the procurement of coal and gas under various coal and gas supply contracts by the Fuel Procurement Division (FPD) of TNB.

- As soon as available but not later than month 5 of the current six month period, the Single Buyer should provide audited report on actual Fuel Cost, Generation Specific Costs, Unit Sold and Revenue collected based on Single Buyer Tariff, FCPT 1 and GSCPT 1 for the preceding six month period. This is to ascertain the amount of over or under recovery of changes in fuel and Generation Specific costs (FCPT 2 and GSCPT 2)

Six month actual revenue

The actual revenue for the six month period should be based on the Single Buyer Tariff, FCPT 1, GSCPT 1, FCPT 2 and GSCPT 2 and actual sales of electricity to customers. The actual generation specific revenue for the Single Buyer should reflect the generation specific revenue received from Customer Services over the relevant six month period.

Explanation of variances

The report should include a detailed explanation of the variances between actual costs of electricity procurement and generation revenue based on the Single Buyer tariff.

Proposed tariff adjustment

The Commission proposes that any adjustments to the Fuel Cost and Other Generation Specific Cost to account for the difference in actual cost and forecasted cost should be implemented in the immediate next six month period. As the actual cost is not available in the immediate six month period it is proposed the pass-through will be based on estimated actual cost and over or under recovery of cost variation will be adjusted accordingly in next preceding six month period as and when the audited actual figure is available

Audit requirement

The Commission will require the fuel cost report prepared by the Single Buyer to be certified as correct by a reputable audit company.

3.3 Approval of proposed tariff adjustment

The Commission will review the tariff adjustment as proposed by the Single Buyer pursuant to the Fuel Cost Adjustment and Other Generation Specific Cost Adjustment and finalise its decision no later than 15 working days after receipt of the Estimated Actual Generation Cost reports. Following the Commission’s final decision, it will adopt the following approval process in reviewing and approving any tariff adjustment based on the Imbalance Cost Pass-Through mechanism.

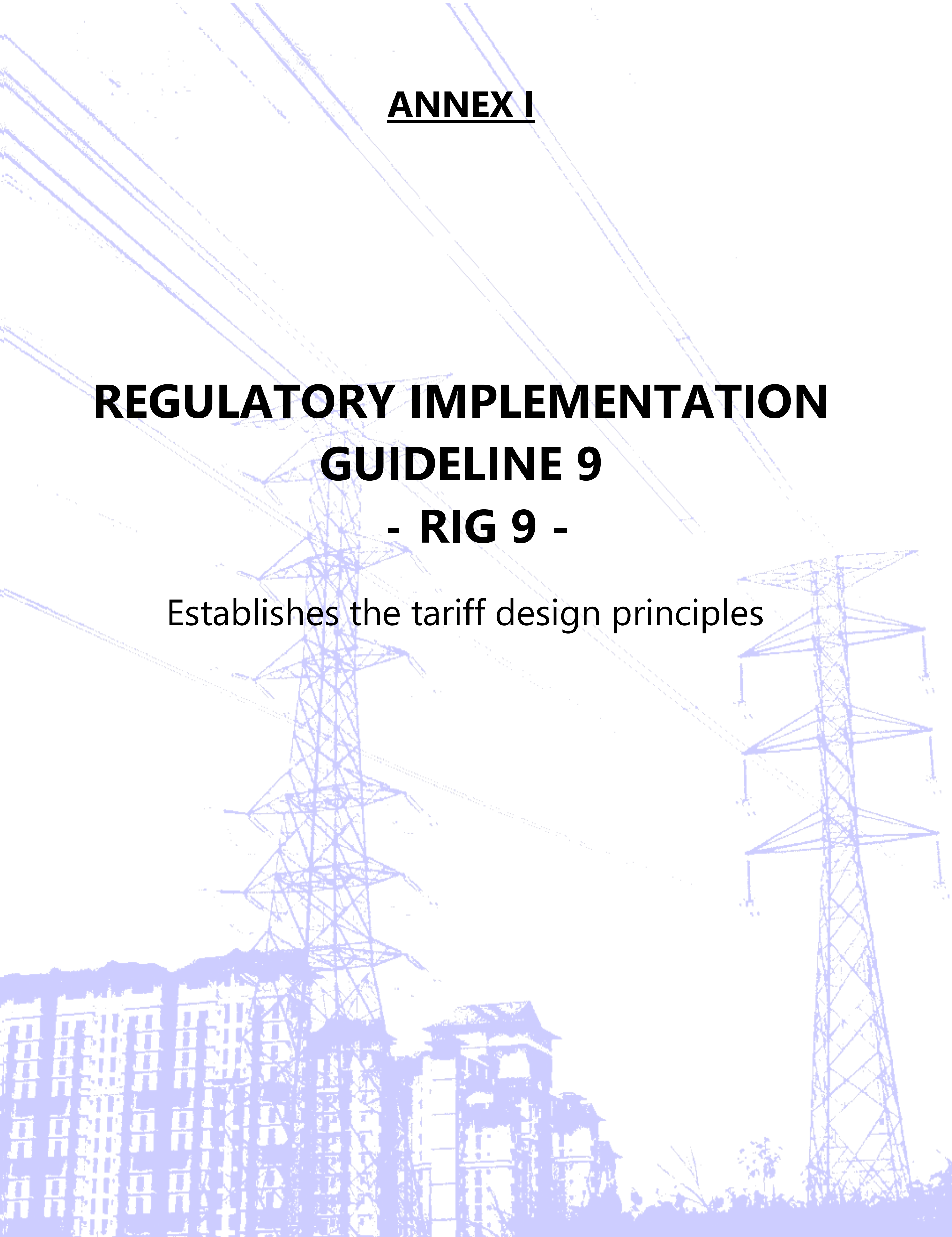
- If the proposed adjustment to the generation specific tariff component of the Single Buyer Tariff is less than 7%, the Commission will approve and implement the proposed tariff adjustment in accordance with this guideline.
- If the proposed adjustment to the generation specific tariff component of the Single Buyer Tariff is equal to or greater than 7%, the Commission will recommend its decision to the Minister for approval.

ANNEX I

REGULATORY IMPLEMENTATION GUIDELINE 9

- RIG 9 -

Establishes the tariff design principles



1. Objective

The objectives of RIG 9 are as follows:

- Set out the principles to be followed by TNB when proposing prices; and
- Establish the annual price approval process.

2. Pricing principles

There are two overarching principles that should be applied by TNB when proposing tariffs, and which will form the basis for the Commission's assessment of pricing proposals:

- Cost recovery: Prices should allow TNB to recover its operating and maintenance costs and achieve an appropriate rate of return on its investments, ensuring the financial viability of the regulated business; and
- Cost reflectivity (allocative efficiency): Prices should reflect the cost of delivering services (that is, the costs imposed on TNB by electricity consumers), thereby providing appropriate incentives for customers concerning how and when they use electricity.

2.1 Cost recovery

Cost recovery is addressed via the Tariff Setting Framework and form of price control, as set out in Regulatory Implementation Guideline Number 2 (RIG 2), and the establishment of Annual Revenue Requirements, as set out in Regulatory Implementation Guideline Number 3 (RIG 3).

2.2 Cost reflectivity

Economic efficiency suggests that prices for a customer group should be set between an upper bound representing stand-alone costs and a lower bound representing avoidable or incremental cost, where:

- Stand-alone cost is the total cost TNB would incur if it provided services only to the customer group in question, with no other service provided to any other customer group; and
- Avoidable cost is the cost that would be avoided by not serving a particular customer group.

There is no single generally accepted method for calculating stand-alone cost or avoidable cost, and in practice there is likely to be a wide range of potential tariffs and tariff structures that would fall within these bounds.

In justifying tariffs and tariff components, the Commission expects that TNB will have regard to an accepted methodology for estimating the cost of serving customers, such that prices reflect the impact of electricity use by customers on decisions by TNB concerning upgrades and augmentations to generation and transmission infrastructure (that is, the Long Run Marginal Cost (LRMC) of supply). For example, costs of generation passed from the Single Buyer to the Customer Services business entity (and on to final customers) should reflect the load profile of customer groups or segments and TNB's associated network planning considerations (such as type of generation required to serve that customer group).

LRMC is generally estimated on either an incremental or greenfields basis.

Incremental methods for estimating LRMC include the Average Incremental Cost (AIC) and Marginal Incremental Cost (MIC) approaches. These approaches are entirely forward looking and ignore sunk costs (by assuming there is existing plant available to meet demand). Where there is excess capacity in a system, or the next supply augmentation is some way off, estimates of incremental LRMC may be very low, suggesting that very low variable usage charges should be applied. Very low variable charges may limit the effectiveness of tariffs in terms of:

- Customers' ability to exercise control over their bills by changing usage patterns; and
- The provision of incentives for customers to use energy efficiently.

The greenfields approach (sometimes referred to as the stand-alone load or long run average cost (LRAC) approach) assumes there is currently no plant available to meet demand, and involves the estimation of an optimised replacement cost to meet existing and future demand.

The Commission is open to considering alternative approaches to estimating the cost of serving customers that meet the objectives of the pricing principles. However, given the uncertainty involved in appraising costs over a long-term timeframe, any estimates of LRMC should be treated with caution. Regardless of the approach applied, prices should still fall within the bounds of stand-alone and avoidable cost and send appropriate signals to customers about how and when they consume electricity.

2.3 Implementation issues

In addition to the high level pricing principles outlined above, TNB must have regard to the following issues when developing its tariff structure proposals:

- Recovery of costs: TNB's prices should be structured so as to ensure that it recovers its revenue requirement for each business entity over the Regulatory Term.
- Consistency with Government policy: TNB's prices should be consistent with any applicable Government policy concerning impacts on vulnerable customer groups and

economic and regional development issues, including employment and investment growth.

- Customer impacts: Where adverse impacts on customers from changes to, or increases in, tariffs are identified, TNB should provide details of its strategies for addressing customer impacts.
- Transparency and simplicity: For any price signals to be effective, tariffs must be able to be readily understood by customers. Highly complex tariff structures, while potentially being more cost reflective, may not be effective in influencing customer behaviour if they are not clearly understood.
- Costs and benefits of changes to tariff structures: Where TNB proposes to revise its tariff structures it should take into account the costs of implementing the new tariffs (such as changes to billing systems and informing and educating customers) with the anticipated benefits in terms of improving cost reflectivity or incentives for customers to change behaviour.

3. Tariff setting process

This section of the guideline sets out the annual tariff approval process for within-period tariff adjustments.

As noted in RIG 3, the final tariff paid by customers (the total average electricity tariff) is set by the Customer Services business entity and is the sum of all Component Average Tariffs for each of the TNB business entities. Customer Services should allocate the costs imposed by customers on TNB business entities to the tariffs charged to specific customer groups based on information from each business entity about the cost of providing services to those customer groups. TNB’s regulatory submission should also set out detailed information that demonstrates the calculation of the total average electricity tariff, including, for each tariff category and tariff component:

- The amount of the tariff
- Criteria for the application of the tariff
- Customer numbers
- Current and expected volumes
- Current and expected revenue.

The following worked example shows how the total average tariff is calculated from a simple case where the regulated entity has two separate tariff categories, each with a number of components.

Fig: Example of calculation of the total average tariff

	Unit	Charge	Sales (MWh)	Revenue (RM)
Tariff category 1: domestic tariff				
Customer numbers 20,000				
First 100 kWh	sen/kWh	15	400	60,000
101 - 200 kWh	sen/kWh	20	2,500	500,000
201 kWh and above	sen/kWh	25	11,000	2,750,000
Minimum monthly charge	RM	3		
Tariff category 2: industrial tariff				
Customer numbers 10,000				
Peak charge (9am to 3pm)	sen/kWh	33	66,000	21,780,000
Off-peak charge (3pm to 9am)	sen/kWh	25	40,000	10,000,000
Demand charge	RM/kW	20	NA	10,000
Total			119,900	35,100,000
Total average tariff	**sen/kWh**	**29.27**		

Note: the revenue and sales for the minimum monthly charge are included in the First 100 kWh block of the domestic tariff

Any changes in components of the total average electricity tariff due to Revenue Cap adjustments or Actual Cost adjustments for individual business entities will flow through directly to prices charged to final customers.

The total average electricity tariff constraint allows TNB to increase (or decrease) some individual tariffs for customer groups by more or less than others, so long as the total average electricity tariff condition is met. The Commission will set side constraints on the movement of individual tariffs to guard against customers being subject to price shocks.

As noted in RIG 2, under the proposed revenue cap and actual cost arrangements for the Transmission, System Operation and the Single Buyer business entities, the period of tariff adjustment are as follows:

- ***Transmission revenue cap adjustments***: It is proposed that this adjustment is done on regulatory term basis;
- ***System Operations revenue cap adjustment***: It is proposed that this adjustment is done on regulatory term basis;
- ***Single Buyer fuel price adjustment (for the generation specific tariff component)***: It is proposed that this adjustment is done every six months;
- ***Single Buyer actual cost adjustment (for the generation specific tariff component)***: It is proposed that this adjustment is done every six months; and

- ***Single Buyer Operations revenue cap adjustment (for the other operational cost specific tariff component)***: It is proposed that this adjustment is done on regulatory term basis.

The Commission proposes that rebalancing of tariffs will only occur at regulatory term intervals, with the six month adjustments for fuel prices and Single buyer actual generation costs being enacted as a direct and proportional pass-through to all tariffs.

3.1 Tariff adjustments

The following process is proposed for tariff adjustments:

- Two months prior to the end of the regulatory year, TNB will be required to submit its proposed tariff schedule to the Commission, with any rebalancing proposals accompanied by evidence of compliance with the pricing principles and implementation issues. Adjustments for revenue under or over recovery under the revenue cap arrangements will be based on an estimate of revenue for the current regulatory term (combining the most recent actual data and forecasts for the remainder of the regulatory term). Any difference between estimated revenue and actual revenue will need to be accounted for in revenue cap adjustments in subsequent regulatory terms.
- The Commission will then assess the tariff proposed against compliance with the total average electricity tariff constraint, and the pricing principles and implementation issues.
- Where inconsistencies with the total average electricity tariff constraint, pricing principles or implementation issues are identified, the Commission may request clarification from TNB or require TNB to re-submit its tariff proposal.
- Following approval by the Commission, TNB will publish its approved tariffs on its website at least 10 business days prior to the commencement of the next regulatory year.

ANNEX J

REGULATORY IMPLEMENTATION GUIDELINE 10

- RIG 10 -

Establishes the Regulatory Accounts process: specify timing, reconciliation to audited accounts and explanation of variances

1. Objective

The objective of RIG 10 is to set out the framework for the development of regulatory accounts for each of TNB's regulated business entities[1]. The purpose of the Regulatory Accounts will be to assist in the assessment of TNB's actual performance in terms of:

- financial benchmarks, operating and capital expenditures that make up the revenue requirement; and
- operational performance standards and key performance indicators, developed in accordance with the framework is set out in RIG 6.

2. Background

The regulatory framework proposed by the Commission in RIG 2, RIG 3 and RIG 4 will rely on the submission of a range of information by the TNB business entities to build up a revenue requirement and set prices for the Regulatory Term, including forecasts of:

- capital expenditure and operating expenditure for each TNB business entity;
- revenue for each business entity; and
- operational performance and performance against indicators and targets relating to network performance and customer service.

During the course of the Regulatory Term, and at the end of the Regulatory Term, the Commission will assess actual outcomes against forecasts and benchmarks for the purposes of:

- updating the regulatory asset base (RAB) for actual capital expenditure and customer contributions and depreciation (the process for updating the RAB is set out in RIG 3)[2];
- making price adjustments for actual cost outcomes for the Single Buyer Generation under the Actual Cost regime (the Actual Cost regime is set out in RIG 2)[3];
- making price adjustments for actual revenue outcomes for the Transmission, System Operations and Single Buyer Operations under the Revenue Cap regimes (see RIG 2);
- making price adjustments for actual operating expenditure outcomes the efficiency carry over scheme (see RIG 3); and
- forecasts of operational performance and performance against indicators and targets relating to network performance and customer service (as set out in RIG 6).

[1] The five TNB business entities are specified in RIG 1.
[2] The process for updating the RAB is set out in RIG 3.
[3] The Actual Cost regime is set out in RIG 2.

In addition to audited financial accounts, the Commission is proposing to require the TNB business entities to submit Regulatory Accounts to assess actual performance against the forecasts of operating expenditure, capital expenditure and operational performance which form the basis of prices for the Regulatory Term.

Regulatory Accounts are required because while audited financial accounts provide a description of the financial performance of the business as a whole, a number of items are treated differently for regulatory purposes (for example, regulatory depreciation of the regulatory asset base (RAB) and the treatment of customer contributions). Also, there will be a range of expenditure and revenue items included in the financial accounts that relate to services that are not subject to regulation and therefore should be excluded from the Regulatory Accounts and development of prices for the TNB business entities.

Regulatory Accounting information is critical to enable to Commission to assess both the past performance of the TNB business entities, and to inform the establishment of the revenue requirement, operational performance targets and prices in future Regulatory Terms.

In addition, the process of maintaining Regulatory Accounts will assist in the implementation of the regulatory framework by providing a clear link between the inputs used for regulatory pricing purposes and the financial statements of TNB as a whole.

3. Form of Regulatory Accounts

The Regulatory Accounts should be drawn from the audited financial accounts of the TNB business entities. However, as noted above, there are a number of differences between financial accounting information and regulatory data.

The translation of business performance data from the financial accounts to the Regulatory Accounts should be consistent with the Commission's proposed regulatory framework set out in the Regulatory Implementation Guidelines, in particular:

- The revenue requirement principles in RIG 3;
- The principles of allocating joint costs in RIG 7; and
- The pricing principles in RIG 9.

The format of the Regulatory Accounts will be the same as that used for the data input templates in Appendix 1 to RIG 5. In particular, the Regulatory Accounts should include the same level of detail with regard to categories of operating and capital expenditure, the breakdown of the RAB, and allocation of joint costs as has been included in the original regulatory submission from the TNB business entities that make up the revenue requirement.

This will ensure that the Commission is readily able to compare the actual performance of the TNB entities against the forecasts used to establish prices and performance standards.

3.1 Development of Regulatory Accounts

The Regulatory Accounts submitted by TNB should be accompanied by a submission setting out the process by which the Regulatory Accounts were drawn from the audited financial accounts, and any adjustments made in the process of translation.

The key issues to be covered will be:

- a description of how expenditures and revenues for regulated services have been separated from expenditures and revenues for services provided by TNB that are not subject to regulation. This is a key principle of the regulatory framework, as it is important that services provided by TNB that are not subject to regulation (as they are provided in a competitive environment) are not cross-subsidised by revenue earned from regulated services; and
- confirmation that the cost allocation methodology used in translating joint costs from the financial accounts to the Regulatory Accounts is consistent with TNB's cost allocation methodology (as set out in RIG 7).

The translation of data from the audited financial accounts to the Regulatory Accounts (including compliance with the joint cost allocation methodology) should be audited by a reputable accounting firm, preferably the same firm that has audited TNB's financial statements.

FIG: Development of Regulatory Accounts

3.2 Explanation of variances

TNB should provide a submission including a detailed explanation of such variances where variances occur between the actual operating expenditure, capital expenditure and operational performance data in the Regulatory Accounts and the forecast data provided to the Commission in the templates in Appendix 1 to RIG 5 prior to the commencement of the Regulatory Term.

The explanation of variances between the forecast and actual expenditure and performance should include (but not be limited to) descriptions of any operating cost over runs or efficiency gains, changes to the timing or amount of capital expenditure and forecasting error with respect to electricity sales.

3.3 Commentary on operational performance

The Regulatory Accounts should also include a detailed commentary about the operational performance of the TNB business entities, encompassing network performance and performance against customer service standards. This commentary should be in the form of a review by management highlighting key areas of concern for the business and provide details of any programs or revisions to processes to be implemented by TNB to address these concerns.

4. Implementation process

The Commission proposes the following implementation plan:

- 2 months following the finalisation of TNB's financial accounts, TNB will be required to provide the Commission with its Regulatory Accounts;

- The Regulatory Accounts will be in the same format as the data supplied in the initial submission for the Regulatory Term, as set out in the templates in Appendix 1 (see RIG5); and
- The Regulatory Accounts must be audited by a reputable firm – preferably the same firm used by TNB for auditing its financial accounts and include a declaration by senior management of TNB confirming the veracity of the Regulatory Accounts and accompanying submissions.

4.1 Review of regulatory accounts

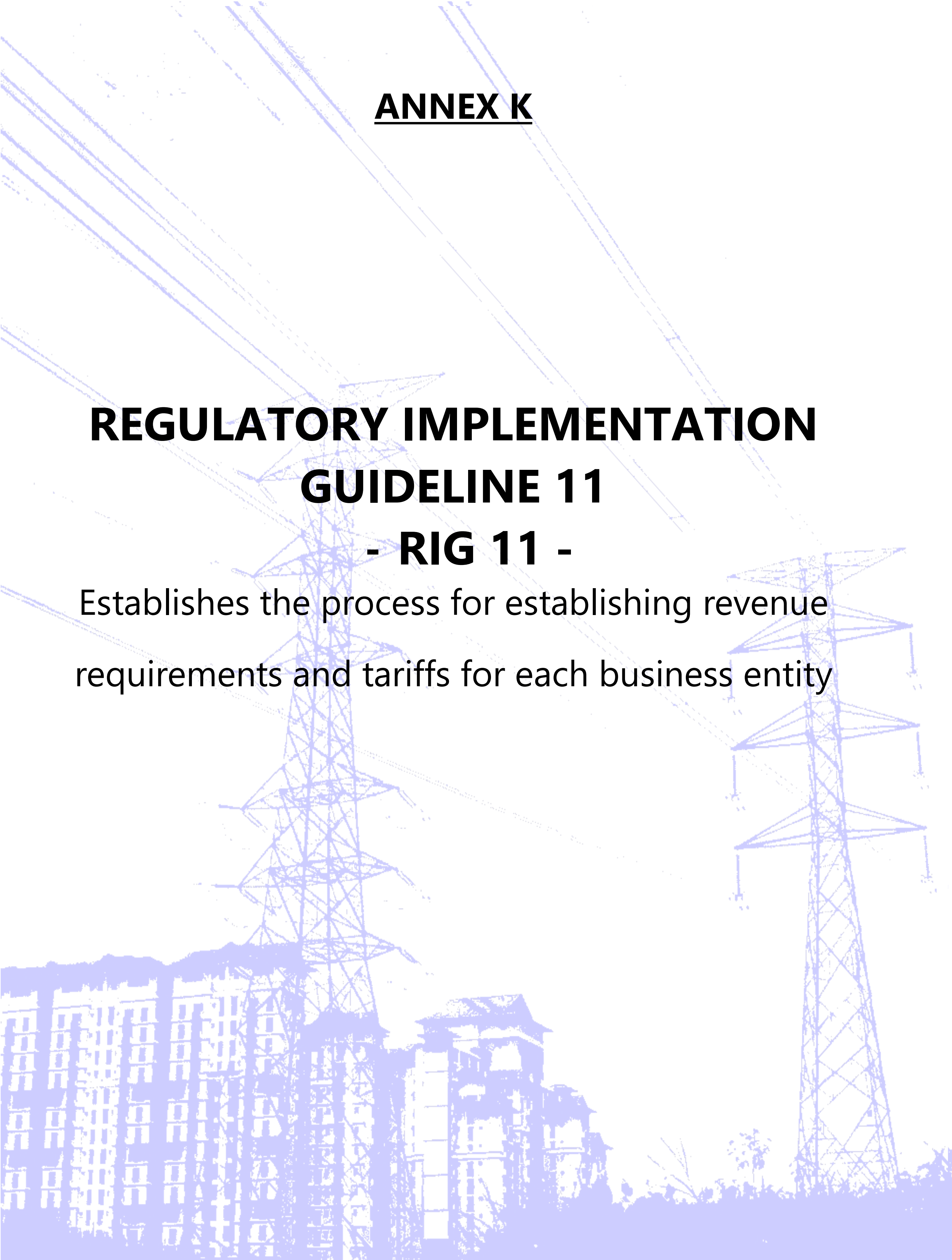
The Regulatory Accounts and accompanying reports submitted by TNB on its performance will also allow the Commission to assess trends in expenditure and revenue and inform the assessment of future regulatory proposals by TNB concerning forecasts of operating and capital expenditure and performance targets in subsequent Regulatory Terms. The audited Regulatory Accounts will be primarily used by the Commission to:

- Update the RAB with actual capital additions made over the Regulatory Term (including deductions for customer contributions) and ensure that the regulatory depreciation applied is appropriate;
- Review operating expenditure and the efficiency carry over amounts for the efficiency carry over scheme;
- Review revenues and costs for the purposes of making adjustments under the Revenue Cap and Actual Cost regimes; and
- Assess TNB's performance against its targets for performance indicators (as set out in RIG 6), and in subsequent Regulatory Terms, inform the incentive or penalty amounts associated with either meeting or falling short of the targets.

In assessing the audited Regulatory Accounts, the Commission may request further details from TNB on any particular areas of concern or where it considers that variances between the forecast data in the revenue requirement templates and the Regulatory Accounts are not adequately explained.

It should also be noted that while the Regulatory Accounts will provide a key input into the Commission's assessment of actual outcomes, the Commission will still assess past capital expenditure and operating expenditure undertaken by TNB to ensure that it is prudent and efficient.

ANNEX K



REGULATORY IMPLEMENTATION GUIDELINE 11

- RIG 11 -

Establishes the process for establishing revenue requirements and tariffs for each business entity

1. Objective

The objective of RIG 11 is to outline the regulatory review process to be followed for the first regulatory period.

2. Overview of regulatory review process

Following the finalisation of the Regulatory Implementation Guidelines and price review templates, the regulatory review process will comprise the following key elements:

- TNB to propose service standards for each of its business entities (see RIG 6 on operating performance indicators). The Commission will decide upon TNB's proposed service standards before considering required revenue and prices;
- TNB to develop its proposal for its annual revenue requirement to meet its service standards, including targets for operating and capital expenditure (see RIG 3 on revenue requirement principles) and a rate of return of capital expenditure. The Commission will assist TNB with monthly workshops and guidance as required on the development of its proposal; and
- The Commission to approve prices proposed by TNB which will allow it to earn its required revenue, given forecast demand (see RIG 2 on the tariff setting framework and RIG 9 on pricing principles). Following a draft decision on prices, the Commission will consult with relevant stakeholders and may also consider submissions before making its final decision.

2.1 Timeframes and key milestones

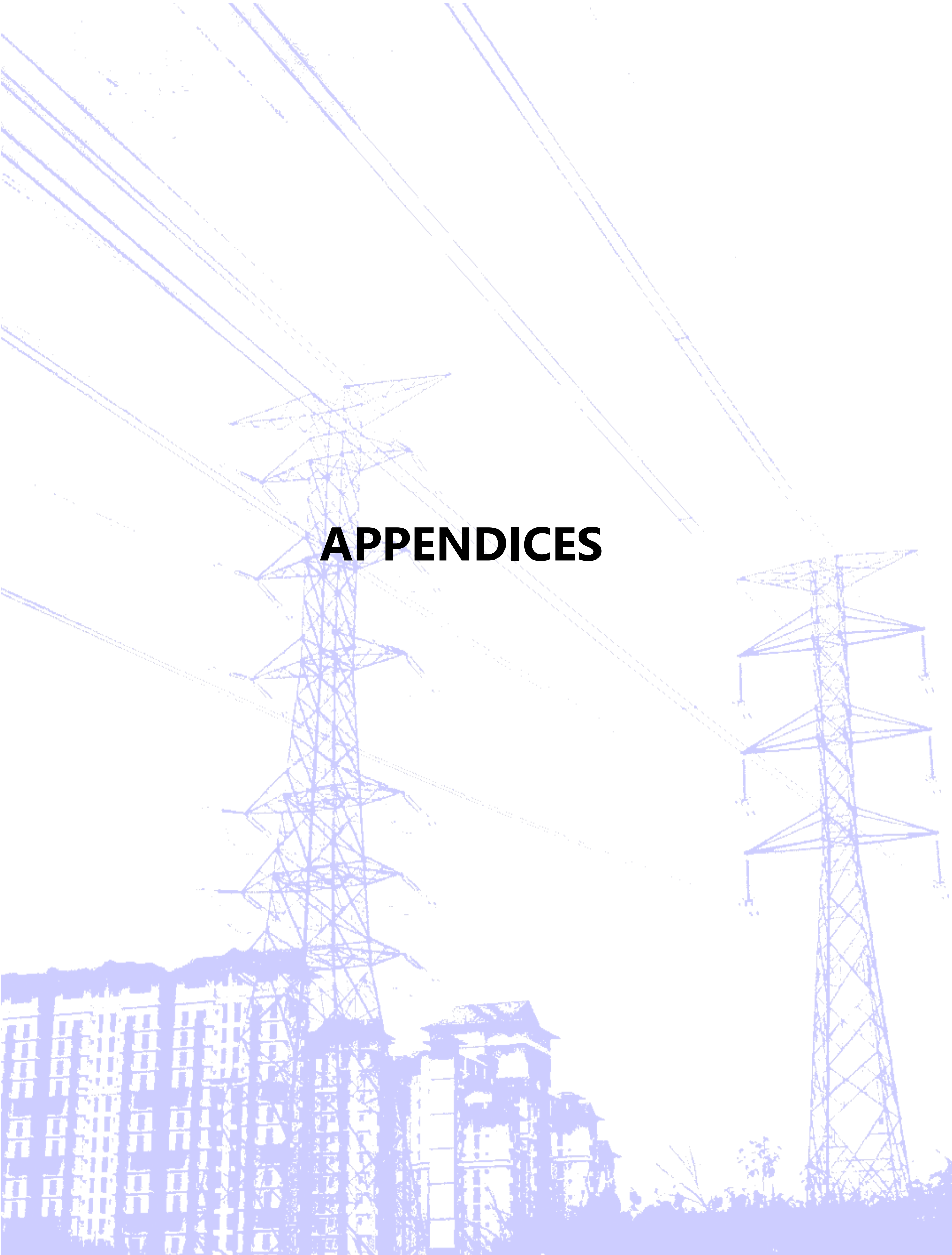
The table below outlines indicative dates and timeframes for each stage of the review and key milestones.

In addition to the two months period for TNB to develop its service standards, the Commission will allow TNB four months to develop its proposal for the review in recognition of the additional time that may be required to liaise with Government and obtain any necessary Ministerial approvals. These are indicative timeframes only, however, the Commission is mindful that it is important to minimise the administrative costs of undertaking regulatory reviews by ensuring they run to schedule.

Table: Process of review

Stage	Indicative dates	Process
Stage 1: RIGs	January 2012	Commission to issue final RIGs
Stage 2: Single Buyer Rules	May 2012	Study on Single Buyer Rules completed
Stage 3: Service standards	February 2012 – March 2012	TNB to develop proposed service standards and targets in accordance with RIG 6. Each of the TNB business entities will propose operational performance indicators, with a lower and upper bound performance target.
	April 2012	Commission draft decision on service standards.
	June 2012	Commission final decision on service standards. The Commission will consult with the TNB business entities and other stakeholders as required in making its decision.
Stage 4: TNB submission to review (4 months)	July 2012	TNB to prepare its submission covering four (4) years (Sept 2013- Aug 2017) to the review in accordance with the RIGs and services standards.
	(no later than) October 2012	TNB to provide the Commission with completed Revenue Requirement Model and any relevant accompanying documentation.
Stage 5: Draft decision (6 months)	November 2012 – April 2013	Commission to assess TNB's proposal and make a draft decision on prices for Sept 2013 to Aug 2014 (final), Sept 2014- Aug 2017 (draft) Public Consultation
Stage 6: Final decision (3 months)	May 2013 – July 2013	Following the release of the draft decision, the Commission will consult with relevant stakeholders, including government, the Economic Planning Unit (EPU), TNB and customer groups. The Commission may also consider submissions from TNB and other parties on its draft decision.
	August 2013	The Commission to release its final decision.
Sept 2013 – August 2014		IBR trial run starts on Sept 2013 to Aug 2014 for one year TNB is to submit for Sept 2014 – Aug 2017 regulatory period for final approval
Sept 2014 – Aug 2017 :	**First Regulatory Period of Full Incentive-based Regulation Regime**	

APPENDICES



TNB Revenue Requirement Model - Post Tax Nominal

Single Buyer Generation Inputs

IPP Information

IPP general information

Name	Capacity (MW)	Type (Base, Mid, peaking)	Fuel	Average net heat rate (mmBtu/MWh)	Contract end date (mm/yyyy)
YTL					
GSP					
PHLN					
SEV					
GB3					
PTEK					
PGLA					
PDP					
TTPC					
PRAI					
TBIN					
JEV					
CUF					
JMJG					
KEV GF1					
KEV GF2					
KEV GF4					
KEV GF3					
IPP 19					
IPP 20					

IPP dispatch information

		Base year dispatch (MWh)	Forecast Period dispatch (MWh)						Trial Reg. Period - dispatch (MWh)			Regulated Period dispatch (MWh)								
					Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
Start Date		1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date		31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
YTL																				
GSP																				
PHLN																				
SEV																				
GB3																				
PTEK																				
PGLA																				
PDP																				
TTPC																				
PRAI																				
TBIN																				
JEV																				
CUF																				
JMJG																				
KEV GF1																				
KEV GF2																				
KEV GF4																				
KEV GF3																				
JMJG4	Coal																			
New C2	Coal																			
IPP 20																				

IPP Capacity Payment (RM) - (CRF and FOR)

		Base year capacity payment	Forecast capacity payment						Trial Reg.Period -Forecast capacity payment			Regulatory Period - forecast capacity payment								
					Year 1 total			Year 2 total			Year 3 total			Year 3 total			Year 3 total			Year 3 total
Start Date		1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date		31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
YTL																				
GSP																				
PHLN																				
SEV																				
GB3																				
PTEK																				
PGLA																				
PDP																				
TTPC																				
PRAI																				
TBIN																				
JEV																				
CUF																				
JMJG																				
KEV GF1																				
KEV GF2																				
KEV GF4																				
KEV GF3																				
JMJG4																				
New C2																				
IPP 20																				

IPP Variable Cost and fixed O&M (RM)

		Base year cost payment	forecast variable cost						Trial Reg.Period -Forecast Variable Cost			Regulatory Period - forecast variable cost								
					Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
Start Date		1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date		31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
YTL																				
GSP																				
PHLN																				
SEV																				

GB3																			
PTEK																			
PGLA																			
PDP																			
TTPC																			
PRAI																			
TBIN																			
JEV																			
CUF																			
JMJG																			
KEV GF1																			
KEV GF2																			
KEV GF4																			
KEV GF3																			
JMJG4																			
New C2																			
IPP 20																			

IPP Fuel Cost (RM)

	Base year cost payment	Regulatory Period - forecast fuel cost						Trial Reg.Period -Forecast Fuel Cost			Regulatory Period - forecast fuel cost								
				Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
Start Date	1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date	31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
YTL																			
GSP																			
PHLN																			
SEV																			
GB3																			
PTEK																			
PGLA																			
PDP																			
TTPC																			
PRAI																			
TBIN																			
JEV																			
CUF																			
JMJG																			
KEV GF1																			
KEV GF2																			
KEV GF4																			
KEV GF3																			
JMJG4																			
New C2																			
IPP 20																			

TNB Genaration Information

TNB Generation general information

Name	Capacity (MW)	Type (Base, Mid, peaking)	Fuel	Average net heat rate (mmBtu/MWh)	Contract end date (mm/yyyy)		
TJPS-GF1						Port Dickson 1	
TJPF-GF2						Port Dickson 2	
SJSI Pasir Gudang GF3 U1						Pasir Gudang	
SJSI Pasir Gudang GF3 U2							
SJSI Pasir Gudang GF1						Pasir Gudang	
SJSI Pasir Gudang GF2 GT6A						Pasir Gudang	
SJSI Pasir Gudang GF2 GT6B							
Paka						Paka	
SJJC Klang GF1						Connaught Brdge	
SJJC Klang GF2 GT3						Connaught Brdge	
SJJC Klang GF2 GT4							
SJJC Klang GF2 GT5							
SJJC Klang GF2 GT6							
PJPS						Serdang	
TEWA						Langkawi	
Gelugor						Gelugor	
Kenyir						Kenyir	
Pergau						Pergau	
Cameron Highlands						Cameron Highlands	
Ulu Trgnu							
Jelai							
New Hydro							
Sungai Perak						Sungai Perak	

TNB Generation dispatch information

	Base year dispatch (MWh)	Regulatory Period - Forecast Dispatch (MWh)						Trial Reg.Period -Forecast Dispatch			Regulatory Period - Forecast Dispatch (MWh)								
				Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
Start Date	1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date	31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
TJPS-GF1																			
TJPF-GF2																			
SJSI Pasir Gudang GF3 U1																			
SJSI Pasir Gudang GF3 U2																			
SJSI Pasir Gudang GF1																			
SJSI Pasir Gudang GF2 GT6A																			
SJSI Pasir Gudang GF2 GT6B																			
Paka																			
SJJC Klang GF1																			
SJJC Klang GF2 GT3																			
SJJC Klang GF2 GT4																			
SJJC Klang GF2 GT5																			
SJJC Klang GF2 GT6																			
PJPS																			
TEWA																			
Gelugor																			

Kenyir																			
Pergau																			
Cameron Highlands																			
Ulu Trgnu																			
Jelai																			
New Hydro																			
Sungai Perak																			

TNB Generation Capacity Payment (RM) - (CRF and FOR)

	Base year capacity payment	Regulatory Period - forecast capacity payment						Trial Reg.Period -Forecast Capacity Cost			Regulatory Period - forecast capacity payment								
				Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
Start Date	1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date	31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
TJPS-GF1																			
TJPF-GF2																			
SJSI Pasir Gudang GF3 U1																			
SJSI Pasir Gudang GF3 U2																			
SJSI Pasir Gudang GF1																			
SJSI Pasir Gudang GF2 GT6A																			
SJSI Pasir Gudang GF2 GT6B																			
Paka																			
SJJC Klang GF1																			
SJJC Klang GF2 GT3																			
SJJC Klang GF2 GT4																			
SJJC Klang GF2 GT5																			
SJJC Klang GF2 GT6																			
PJPS																			
TEWA																			
Gelugor																			
Kenyir																			
Pergau																			
Cameron Highlands																			
Ulu Trgnu																			
Jelai																			
New Hydro																			
Sungai Perak																			

TNB Generation variable cost(RM)

	Base year cost payment	Regulatory Period - forecast variable cost						Trial Reg.Period -Forecast Variable Cost			Regulatory Period - forecast variable cost								
				Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
Start Date	1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date	31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
TJPS-GF1																			
TJPF-GF2																			
SJSI Pasir Gudang GF3 U1																			
SJSI Pasir Gudang GF3 U2																			
SJSI Pasir Gudang GF1																			
SJSI Pasir Gudang GF2 GT6A																			
SJSI Pasir Gudang GF2 GT6B																			
Paka																			
SJJC Klang GF1																			
SJJC Klang GF2 GT3																			
SJJC Klang GF2 GT4																			
SJJC Klang GF2 GT5																			
SJJC Klang GF2 GT6																			
PJPS																			
TEWA																			
Gelugor																			
Kenyir																			
Pergau																			
Cameron Highlands																			
Sungai Perak																			

TNB Generation fuel cost (RM)

	Base year cost payment	Forecast fuel cost						Trial Reg.Period -Forecast Fuel Cost			Regulatory Period - forecast fuel cost								
				Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
Start Date	1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
End Date	31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
TJPS-GF1																			
TJPF-GF2																			
SJSI Pasir Gudang GF3 U1																			
SJSI Pasir Gudang GF3 U2																			
SJSI Pasir Gudang GF1																			
SJSI Pasir Gudang GF2 GT6A																			
SJSI Pasir Gudang GF2 GT6B																			
Paka																			
SJJC Klang GF1																			
SJJC Klang GF2 GT3																			
SJJC Klang GF2 GT4																			
SJJC Klang GF2 GT5																			
SJJC Klang GF2 GT6																			
PJPS																			
TEWA																			
Gelugor																			
Kenyir																			
Pergau																			
Cameron Highlands																			
Ulu Trgnu																			
Jelai																			
New Hydro																			
Sungai Perak																			

Summary of gas and coal commodity price assumptions

		Base	Regulatory Period - forecast						Trial Reg.Period -Forecast Commodity Price			Regulatory Period - forecast commodity price								
					Year 1 total			Year 2 total			Year 3 total			Year 4 total			Year 5 total			Year 6 total
		1/09/2010	1/09/2011	1/03/2012	1/09/2011	1/09/2012	1/03/2013	1/09/2012	1/09/2013	1/03/2014	1/09/2013	1/09/2014	1/03/2015	1/09/2014	1/09/2015	1/03/2016	1/09/2015	1/09/2016	1/03/2017	1/09/2016
		31/08/2011	29/02/2012	31/08/2012	31/08/2012	28/02/2013	31/08/2013	31/08/2013	28/02/2014	31/08/2014	31/08/2014	28/02/2015	31/08/2015	31/08/2015	29/02/2016	31/08/2016	31/08/2016	28/02/2017	31/08/2017	31/08/2017
IPP fuel commodity price assumptions																				
Gas																				
Dispatch	MWh																			
Cost	RM																			
Commodity price	RM/MWh																			
Coal																				
Dispatch	MWh																			
Cost	RM																			
Commodity price	RM/MWh																			
TNB Generation fuel commodity price assumptions																				
Gas																				
Dispatch	MWh																			
Cost	RM																			
Commodity price	RM/MWh																			
Coal																				
Dispatch	MWh																			
Cost	RM																			
Commodity price	RM/MWh																			
Total (IPP plus TNB Generation)																				
Total gas																				
Dispatch	MWh																			
Total costs	RM																			
Commodity price	RM/MWh																			
Total coal																				
Dispatch	MWh																			
Total costs	RM																			
Commodity price	RM/MWh																			

TNB Revenue Requirement Model - Post Tax Nominal

Demand and summary Single Buyer Generation costs

Demand

		Base	Forecast		Trial Reg.Prd Forecast	Regulatory Period - Forecast		
	Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
	End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Demand Forecast	MWh							
Losses	%							
TNB Generation dispatch	MWh							
IPP dispatch	MWh							
Total dispatch	**MWh**							
Check								

Single Buyer Generation cost for TNB Generation

		Base	Forecast		Trial Reg.Prd Forecast	Regulatory Period - Forecast		
	Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
	End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Capacity Payment	RM							
Variable cost and fixed O&M	RM							
Fuel cost	RM							
Fuel cost breakdown								
Gas	RM							
Coal	RM							
Other	RM							

Single Buyer Generation cost for IPPs

		Base	Regulatory Period - Forecast		Trial Reg.Prd Forecast	Regulatory Period - Forecast		
	Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
	End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Capacity Payment	RM							
Variable cost and fixed O&M	RM							
Fuel cost	RM							
Fuel cost breakdown								
Gas	RM							
Coal	RM							
Other	RM							

TNB Revenue Requirement Model - Post Tax Nominal

Regulatory Asset Base inputs for TNB Generation (RM)

TNB Generation Regulatory Asset Base Inputs

Opening Regulatory Asset Base (RAB) for Base Year - TNB Generation

Generation Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
Freehold Land			
Short Leasehold Land			
Long Leasehold Land			
Buildings & Civil Works			
Plant & Machinery			
Mains and Lines			
Distribution Services			
Meters			
Public Lighting			
Furniture and Fittings			
Motor Vehicles			
Name of Asset 12			
Name of Asset 13			

Depreciation Schedule Opening RAB - TNB Generation

	Base	Forecast		Trial. Reg Prd	Regulartory Period		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 12							
Name of Asset 13							

Forecast Capex - TNB Generation

	Base	Forecast		Trial. Reg Prd	Regulartory Period		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 12							
Name of Asset 13							

Capital Allowances Inputs: TNB Generation

Base written down tax asset value : TNB Generation

Generation Asset Category	Base Written Down Tax Value	Tax Capital Allowances Rates for Existing Assets	Capital Allowances for New Assets Year 1	Capital Allowances for New Assets Year 2+
Freehold Land				
Long Leasehold land				
Short Leasehold Land				
Buildings				
Plant & Machinery				
Furniture & Fittings				
Vehicles				
Net Capital WIP/Asset Under Construction				
Public Lighting				
Furniture and Fittings				
Motor Vehicles				
Name of Asset 12				
Name of Asset 13				

Forecast capital allowances on existing written down tax asset: TNB Generation

	Base	Forecast		Trial. Reg Prd	Regulartory Period		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							

Long Leasehold land				
Short Leasehold Land				
Buildings				
Plant & Machinery				
Furniture & Fittings				
Vehicles				
Net Capital WIP/Asset Under Construction				
Public Lighting				
Furniture and Fittings				
Motor Vehicles				
Name of Asset 12				
Name of Asset 13				

TNB Revenue Requirement Model - Post Tax Nominal

Regulatory Asset Base inputs (RM)

Transmission Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Transmission

Transmission Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
Freehold Land			
Short Leasehold Land			
Long Leasehold Land			
Buildings & Civil Works			
Plant & Machinery			
Mains and Lines			
Distribution Services			
Meters			
Public Lighting			
Furniture and Fittings			
Motor Vehicles			
Name of Asset 12			
Name of Asset 13			
Total			

Depreciation Schedule Opening Regulatory Asset Base - Transmission

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 12							
Name of Asset 13							

Forecast Capex - Transmission

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							

Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 12							
Name of Asset 13							

Transmission System Operations Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Transmission System Ops

Transmission System Operations Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
Freehold Land			
Short Leasehold Land			
Long Leasehold Land			
Buildings & Civil Works			
Plant & Machinery			
Mains and Lines			
Distribution Services			
Meters			
Public Lighting			
Furniture and Fittings			
Motor Vehicles			
Name of Asset 12			
Name of Asset 13			
Total			

Depreciation Schedule Opening Regulatory Asset Base - Transmission System Ops

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 12							
Name of Asset 13							

Forecast Capex - Transmission System Ops

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							

Short Leasehold Land
Long Leasehold Land
Buildings & Civil Works
Plant & Machinery
Mains and Lines
Distribution Services
Meters
Public Lighting
Furniture and Fittings
Motor Vehicles
Name of Asset 12
Name of Asset 13

Single Buyer Operations Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Single Buyer Operations

Single Buyer Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
Freehold Land			
Short Leasehold Land			
Long Leasehold Land			
Buildings & Civil Works			
Plant & Machinery			
Mains and Lines			
Distribution Services			
Meters			
Public Lighting			
Furniture and Fittings			
Motor Vehicles			
Name of Asset 12			
Name of Asset 13			
Total			

Depreciation Schedule Opening Regulatory Asset Base - Single Buyer Operations

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 12							
Name of Asset 13							

Forecast Capex - Single Buyer Operations

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 12							
Name of Asset 13							

Customer Service Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Retail operations

Retail Operations Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
Name of Asset 1			
Name of Asset 2			
Name of Asset 3			
Name of Asset 4			
Name of Asset 5			
Name of Asset 6			
Name of Asset 7			
Name of Asset 8			
Name of Asset 9			
Name of Asset 10			
Name of Asset 11			
Name of Asset 12			
Name of Asset 13			

Depreciation Schedule Opening Regulatory Asset Base - Retail Operations

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Name of Asset 1							
Name of Asset 2							
Name of Asset 3							
Name of Asset 4							
Name of Asset 5							
Name of Asset 6							
Name of Asset 7							
Name of Asset 8							
Name of Asset 9							
Name of Asset 10							

Name of Asset 11							
Name of Asset 12							
Name of Asset 13							

Forecast Capex - Retail operations

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Name of Asset 1							
Name of Asset 2							
Name of Asset 3							
Name of Asset 4							
Name of Asset 5							
Name of Asset 6							
Name of Asset 7							
Name of Asset 8							
Name of Asset 9							
Name of Asset 10							
Name of Asset 11							
Name of Asset 12							
Name of Asset 13							

Opening Regulatory Asset Base for Base Year - Distribution

Distribution Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
Name of Asset 1			
Name of Asset 2			
Name of Asset 3			
Name of Asset 4			
Name of Asset 5			
Name of Asset 6			
Name of Asset 7			
Name of Asset 8			
Name of Asset 9			
Name of Asset 10			
Name of Asset 11			
Name of Asset 12			
Name of Asset 13			

Depreciation Schedule Opening Regulatory Asset Base - Distribution

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Name of Asset 1							
Name of Asset 2							
Name of Asset 3							
Name of Asset 4							
Name of Asset 5							
Name of Asset 6							
Name of Asset 7							

Name of Asset 8							
Name of Asset 9							
Name of Asset 10							
Name of Asset 11							
Name of Asset 12							
Name of Asset 13							

Forecast Capex - Distribution

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Name of Asset 1							
Name of Asset 2							
Name of Asset 3							
Name of Asset 4							
Name of Asset 5							
Name of Asset 6							
Name of Asset 7							
Name of Asset 8							
Name of Asset 9							
Name of Asset 10							
Name of Asset 11							
Name of Asset 12							
Name of Asset 13							

Opening Regulatory Asset Base for Base Year - Customer Service

Customer Service Asset Category	Accounting Written Down Value	Avg Remaining Life	Avg Asset Life (New Asset)
Freehold Land			
Short Leasehold Land			
Long Leasehold Land			
Buildings & Civil Works			
Plant & Machinery			
Mains and Lines			
Distribution Services			
Meters			
Public Lighting			
Furniture and Fittings			
Motor Vehicles			
Name of Asset 13			

Depreciation Schedule Opening Regulatory Asset Base - Customer Service

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							

Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 13							

Forecast Capex - Customer Service

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 13							

Customer Contributions (deferred income) Inputs

Opening Customer Contributions for Base Year

	Accounting Written Down Value base year	Amortisation rate for existing assets	Amortisation rate for new assets
Total Opening Customer Contribution			

Forecast Customer Contributions

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Customer contributions							

Capital Allowances Inputs: Transmission

Base written down tax asset value : Transmission

Transmission Asset Category	Base written down tax value	Tax Capital Allowances Rates for existing assets	Capital allowances for new assets Year 1	Capital allowances for new assets Year 2+
Freehold Land				
Short Leasehold Land				
Long Leasehold Land				

Buildings & Civil Works				
Plant & Machinery				
Mains and Lines				
Meters				
Public Lighting				
Furniture and Fittings				
Motor Vehicles				
Name of Asset 13				
Name of Asset 13				

Forecast capital allowances on existing written down tax asset

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of Asset 13							
Name of Asset 13							

Capital Allowances Inputs: Transmission System Operation

Base written down tax asset value : Transmission System Ops

Transmission System Operations Asset Category	Base written down tax value	Tax Capital Allowances Rates for existing assets	Capital allowances for new assets Year 1	Capital allowances for new assets Year 2+
Name of Asset 1				
Name of Asset 2				
Name of Asset 3				
Name of Asset 4				
Name of Asset 5				
Name of Asset 6				
Name of Asset 7				
Name of Asset 8				
Name of Asset 9				
Name of Asset 10				
Name of Asset 11				
Name of Asset 12				
Name of Asset 13				

Forecast capital allowances on existing written down tax asset

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Name of Asset 1							
Name of Asset 2							
Name of Asset 3							
Name of Asset 4							
Name of Asset 5							
Name of Asset 6							
Name of Asset 7							
Name of Asset 8							
Name of Asset 9							
Name of Asset 10							
Name of Asset 11							
Name of Asset 12							
Name of Asset 13							

Capital Allowances Inputs: Single Buyer Operations

Base written down tax asset value : Single Buyer Operations

Single Buyer Asset Category	Base written down tax value	Tax Capital Allowances Rates for existing assets	Capital allowances for new assets Year 1	Capital allowances for new assets Year 2+
Name of Asset 1				
Name of Asset 2				
Name of Asset 3				
Name of Asset 4				
Name of Asset 5				
Name of Asset 6				
Name of Asset 7				
Name of Asset 8				
Name of Asset 9				
Name of Asset 10				
Name of Asset 11				
Name of Asset 12				
Name of Asset 13				

Forecast capital allowances on existing written down tax asset

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Name of Asset 1							
Name of Asset 2							
Name of Asset 3							
Name of Asset 4							
Name of Asset 5							
Name of Asset 6							
Name of Asset 7							
Name of Asset 8							
Name of Asset 9							

Name of Asset 10				
Name of Asset 11				
Name of Asset 12				
Name of Asset 13				

Capital Allowances Inputs: Customer Services

Base written down tax asset value : Customer Services

Customer Services Asset Category	Base written down tax value	Tax Capital Allowances Rates for existing assets	Capital allowances for new assets Year 1	Capital allowances for new assets Year 2+
Freehold Land				
Long Leasehold land				
Short Leasehold Land				
Buildings				
Plant & Machinery				
Lines & Mains				
Distribution Services				
Meters				
Public Lighting				
Furniture & Fittings				
Vehicles				
Net Capital WIP/Asset Under Construction				
Total				

Forecast capital allowances on existing written down tax asset

	Base	Forecast		Trial Reg.Prd.	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Long Leasehold land							
Short Leasehold Land							
Buildings							
Plant & Machinery							
Lines & Mains							
Distribution Services							
Meters							
Public Lighting							
Furniture & Fittings							
Vehicles							
Net Capital WIP/Asset Under Construction							

TNB Revenue Requirement Model - Post Tax Nominal

Opex Inputs (RM)

Opex - Transmission

Transmission Opex Category	Base	Forecast		Trial Reg.Prd	Regulatory Period - Forecast		
	1/09/2010 31/08/2011	1/09/2011 31/08/2012	1/09/2012 31/08/2013	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017
Repairs & Maintenance							
Staff Costs							
Insurance							
License Fees & Water Royalty							
Other General Expenses (Exclude Depreciation)							
Other cost category							
Other cost category							
Other cost category							

Opex - Transmission System Operations

Transmission System Ops Opex Category	Base	Forecast		Trial Reg.Prd	Regulatory Period - Forecast		
	1/09/2010 31/08/2011	1/09/2011 31/08/2012	1/09/2012 31/08/2013	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017
Repairs & Maintenance							
Staff Costs							
Insurance							
License Fees & Water Royalty							
*Other General Expenses (Exclude Depreciation)							
Other cost category							
Other cost category							
Other cost category							

Opex - Single Buyer Operations

Single Buyer Operations Opex Category	Base	Forecast		Trial Reg.Prd	Regulatory Period - Forecast		
	1/09/2010 31/08/2011	1/09/2011 31/08/2012	1/09/2012 31/08/2013	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017
Repairs & Maintenance							
Staff Costs							
Insurance							
License Fees & Water Royalty							
*Other General Expenses (Exclude Depreciation)							
Other cost category							
Other cost category							
Other cost category							

Opex - Customer Services

Retail Operations Opex Category	Base	Forecast		Trial Reg.Prd	Regulatory Period - Forecast		
	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Labour							
Maintenance							
Administration							
Mete reading							
Custoemr operations							
Other cost category							
Other cost category							
Other cost category							

Distribution Opex Category	Base	Forecast		Trial Reg.Prd	Regulatory Period - Forecast		
	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Labour							
Maintenance							
Administration							
Mete reading							
Custoemr operations							
Other cost category							
Other cost category							
Other cost category							

Customer Services Opex Category	Base	Forecast		Trial Reg.Prd	Regulatory Period - Forecast		
	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Energy Bulk Purchase							
Fuel Cost							
Repairs & Maintenance							
Staff Costs							
Insurance							
License Fees & Water Royalty							
Other General Expenses (Exclude Depreciation)							
Consumables							

Allocation Matrix

	Transmission	System operations	Single buyer ops	Customer Services	Total
Average RAB					0%
Depreciation					0%
Opex					0%
Capital Allowances					0%

TNB Revenue Requirement Model - Post Tax Nominal

Joint Cost Inputs (RM)

Joint Costs Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year

Other Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
Freehold Land			
Short Leasehold Land			
Long Leasehold Land			
Buildings & Civil Works			
Plant & Machinery			
Mains and Lines			
Distribution Services			
Meters			
Public Lighting			
Furniture and Fittings			
Motor Vehicles			
Name of asset 12			
Name of asset 13			

Depreciation Schedule Opening Regulatory Asset Base

	Base	Forecast		Trial Reg. Prd	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							

Name of asset 12							
Name of asset 13							

Forecast Capex

	Base	Forecast		Trial Reg. Prd	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Short Leasehold Land							
Long Leasehold Land							
Buildings & Civil Works							
Plant & Machinery							
Mains and Lines							
Distribution Services							
Meters							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of asset 12							
Name of asset 13							

Capital Allowances Inputs: Joint Costs

Base written down tax asset value : Other

Other Asset Category	Base written down tax value	Tax Capital Allowances Rates for existing assets	Capital allowances for new assets Year 1	Capital allowances for new assets Year 2+
Freehold Land				
Long Leasehold land				
Short Leasehold Land				
Buildings				
Plant & Machinery				
Furniture & Fittings				
Vehicles				
Net Capital WIP/Asset Under Construction				

Public Lighting				
Furniture and Fittings				
Motor Vehicles				
Name of asset 12				
Name of asset 13				

Forecast capital allowances on existing written down tax asset

	Base	Forecast		Trial Reg. Prd	Regulatory Period - Forecast		
Start Date	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015	1/09/2016
End Date	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016	31/08/2017
Freehold Land							
Long Leasehold land							
Short Leasehold Land							
Buildings							
Plant & Machinery							
Furniture & Fittings							
Vehicles							
Net Capital WIP/Asset Under Construction							
Public Lighting							
Furniture and Fittings							
Motor Vehicles							
Name of asset 12							
Name of asset 13							

Joint Costs Opex

	Base	Forecast		Trial Reg. Prd	Regulatory Period - Forecast		
	1/09/2009	1/09/2010	1/09/2011	1/09/2012	1/09/2013	1/09/2014	1/09/2015
Joint Opex Category	31/08/2010	31/08/2011	31/08/2012	31/08/2013	31/08/2014	31/08/2015	31/08/2016
Repairs & Maintenance							
Staff Costs							
Insurance							
License Fees & Water Royalty							
Other General Expenses (Exclude Depreciation)							
Other cost category							
Other cost category							
Other cost category							

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