BERMUDA

Regulatory Authority (Retail Tariff Methodology) General Determination

BR /2018

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The Regulatory Authority, in the exercise of the power conferred by section 62 of the Regulatory Authority Act 2011, as read with sections 12 and 13 of that Act and sections 6, 14, 17 and 35 of the Electricity Act 2016, makes the following General Determination:

Citation

1 This General Determination may be cited as the Regulatory Authority (Retail Tariff Methodology) General Determination.

Interpretation

2 In this General Determination, unless the context otherwise requires, terms shall have the meaning given in the Regulatory Authority Act 2011, the Electricity Act 2016, and the Schedule to this General Determination.

General Purpose

3 This General Determination establishes the methodology for calculating the electricity retail tariff.

Determination

4 (1) This General Determination is made pursuant to the Consultation Document entitled "Retail Tariffs Design Public Consultation" dated 8 March 2018 and the Regulatory Authority's Decision on it.

(2) Taking into account the received responses to the Consultation Document and for the reasons given in the Decision, the Authority determines that the retail tariff methodology set forth in the Schedule is consistent with the purposes of the Electricity Act 2016, including to seek to:

(a) ensure the adequacy, safety, sustainability and reliability of electricity supply in Bermuda;

(b) encourage electricity conservation and the efficient use of electricity;

(c) promote the use of cleaner energy solutions and technologies;

(d) provide sectoral participants and end-users with non-discriminatory interconnection to transmission and distribution systems;

(e) protect the interests of end-users with respect to prices and affordability, and the adequacy, reliability and quality of electricity service; and

(f) promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

Terms and conditions of General Determination

5 (1) The Schedule to this General Determination has effect.

(2) The Schedule is also published on the Regulatory Authority's website (www.rab.bm) and is also available for inspection at the offices of the Authority (1st Floor, Craig Appin House, 8 Wesley Street, Hamilton HM 11) during ordinary business hours.

Effective Date of General Determination

6 This General Determination shall become effective on the day it is published in the Official Gazette.

Bermuda

Schedule to Regulatory Authority (Retail Tariff Methodology) General Determination

General Determination

Date: 19 October 2018

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This General Determination is made by the Regulatory Authority of Bermuda pursuant to Section 62(1) of the Regulatory Authority Act 2011 ("**RAA**") and in accordance with Sections 6, 14, 17 and 35 of the Electricity Act 2016 ("**EA**") and establishes the methodology for calculating the retail tariff for the electricity sector.

1 Definitions

"Allowed revenue" means the amount of money an entity is allowed to earn in undertaking its regulated business activities, typically on an annual basis.

"Asset life" in regulated tariff setting is the basis for a depreciation calculation.

"Asymmetric incentive scheme" is a regulatory scheme which provides incentives for least-cost provision of services, where the impact of cost outperformance and underperformance, relative to a benchmark, are different.

"Authority" means the Regulatory Authority of Bermuda established under the Regulatory Authority Act 2011 (as defined by the Electricity Act 2016).

"Barrel" is a unit of volume equal to 42 US gallons, or 159 litres.

"Base-rate filings system" means a methodology to determine retail tariffs, which is currently used in the regulation of the electricity sector of Bermuda.

"Bulk generation" means generation using a system with an installed capacity at or above the licence threshold (as defined by the Electricity Act 2016).

"Bulk generation licence" means a licence granted under section 25 of the Electricity Act 2016.

"CAPEX" means capital expenditure, i.e. expenditure related to the acquisition or upgrade of fixed assets.

"Capital structure" means the proportion of debt and equity that an entity uses to finance its activities.

"CAPM" means capital asset pricing model, a methodology commonly used to estimate the cost of equity for an entity.

"Competitive market" means an idealised market in which a large number of firms compete to provide goods and services for a large number of customers.

"Core network OPEX" means operating expenditure related to the regulated activities of the TD&R licensee, excluding the expense of power procurement and "other expenses" as defined in section 35(3)(d) of the Electricity Act 2016.

"Cost allowance" means the amount of money an entity is allowed to earn within its allowed revenue, to recover corresponding costs.

"Cost of capital" means the return on investment required by investors providing funding for an entity's activities.

"Cost of debt" means the return on investment required by an entity's debt holders.

"Cost of equity" means the return on investment required by an entity's equity holders.

“Cost pass-through allowance” means a cost allowance within regulated tariff setting, such that there is no deviation between allowed costs and costs actually borne by an entity.

“CWIP” means Construction Work in Progress, an asset account in which the value of assets under construction is recorded.

“Demand side resources” means the reduced demand for electricity resulting from demand side management (as defined by the Electricity Act 2016);

“Depreciation” means the gradual decrease in the value of an asset through time due to use, wear and tear or obsolescence; within regulatory tariff setting, depreciation also refers to a cost allowance (as a component of allowed revenue) that is determined to allow an entity to recover its capital expenditure.

“Distributed generation” means generation using a system with an installed capacity below the licence threshold (as defined by the Electricity Act 2016).

“Distributed generator” means a person that has a Standard Contract (as defined by the Electricity Act 2016).

“Distribution” means conveying electric power below 22 kilovolts (kV) (as defined by the Electricity Act 2016).

“EA” means the Electricity Act 2016.

“Efficiency” means achieving maximum benefits with minimum resources.

“Economic life” means the estimated lifespan over which an asset is expected to be able to serve its intended purpose.

“Electricity sector” means the regulated industry sector involving the supply, transmission, distribution and consumption of electricity (as defined by the Electricity Act 2016).

“End user” means a person or entity that uses electric power provided by the TD&R licensee on a retail basis (as defined by the Electricity Act 2016).

“Ex ante” means before the event, i.e. this refers to items that are defined before actual results are known.

“Ex post” means after the event, i.e. this refers to items that are based on actual rather than forecast data.

“Facility” means a site where electrical equipment is located to provide some form of electrical service (as defined by the Electricity Act 2016).

“FAR mechanism” means the fuel adjustment rate mechanism designed to recover the cost of fuel used to produce electricity.

“Feed-in tariff” means the pre-determined rate at which renewable energy is purchased by the TD&R licensee from a distributed generator, for a pre-determined period, and under pre-determined conditions in accordance with Part 6 of the Electricity Act 2016

“Fixed Assets” means tangible assets that are not readily convertible to cash (as opposed to liquid assets); this typically refers to plant, property and equipment, which is in service.

“Gearing” is a measure of the extent of debt that an entity has raised; within this report, gearing refers to the ratio of an entity’s net debt to the rate base.

“Generation capacity” means the maximum electrical output that an electricity plant can produce (typically measured in megawatts).

“Generation” means the process of producing electric power. This includes generation of renewable energy (as defined by the Electricity Act 2016).

“Government authorisation fees” means the fees established under section 52 of the Regulatory Authority Act 2011 (as defined by the Electricity Act 2016).

“HCA Approach” means historical cost accounting approach, whereby the value of an asset is based on the original acquisition or construction cost of the asset. Typically, financial statements containing HCA estimates of the book value of assets are stated on a ‘net’ basis, i.e. less accumulated depreciation.

“Incentive regulation” refers to a form of regulation, which involves setting either price or revenue caps linked to an efficient cost forecast. These caps are in place for a fixed period, thereby providing an incentive to outperform .

“Interconnection” means the electrical connection of a generating station of a licensee, or of a distributed generation unit, to the TD&R licensee (as defined by the Electricity Act 2016).

“IPP” means an independent power producer. This is an entity that provides energy, capacity, and ancillary services for commercial purposes at a bulk scale to the electric utility under long-term contracts.

“IRP” means integrated resource plan, an energy plan for the supply of electricity in Bermuda approved by the Authority in accordance with, and set out in the matters required by, Part 8 of the Electricity Act 2016.

“kWh” means kilowatt-hour, a unit of electrical energy equal to one kilowatt of power expended for one hour; the standard unit of measure used for electrical billing.

“kW” means kilowatt, a standard unit of electrical power equal to 1,000 watts.

“Licence” means a valid licence granted by the Authority under the Electricity Act 2016.

“Licensee” means a person that holds a valid licence in accordance with the Electricity Act 2016.

“MRRM” means Minimum Revenue Requirements Method, a form of rate-of-return regulation.

“MW” means megawatt, one million watts, or one thousand kilowatts of electrical power.

“NDC Fund” means National Disaster Contingency Fund, of which the amount is to be determined by the Authority and which must be available at any time during the term of the TD&R licence.

“OPEX” means operating expenditure. This is expenditure incurred in the day to day running of a business.

“Outputs” means measurable characteristics of a licensee’s activities.

“PPA” means power purchase agreement. This is an agreement entered into under section 48 of the Electricity Act 2016 between the TD&R licensee and a bulk generation licensee, approved by the Authority, whereby the TD&R licensee contracts to purchase or acquire electricity generated by the bulk generation licensee as specified in the agreement (as defined by the Electricity Act 2016).

“Price-cap regime” is a type of incentives-based regime where no adjustments to prices due to deviations from volume forecasts are allowed, i.e. volume risk is borne by the regulated entity .

“Review period” means a period for which retail tariffs are determined by the Authority.

“RAA” means the Regulatory Authority Act (2011).

“Rate base roll-forward” means the process by which the value of a rate base is updated over time.

“Rate base” means the total value of assets on which a utility is permitted to earn a return.

“Rate-of-return regulation” means a type of regulation, where tariffs are set at a level that reflects the actual cost of service .

“Regulatory accounts” means accounts that have to be prepared in line with the Regulatory Accounting Instructions.

“Re-opener” means a mechanism which facilitates a change in allowed revenues before the next review period.

“Return on capital” or “return on rate base” means a cost allowance determined to allow a company to recover its cost of capital, as a component of regulatory allowed revenue.

“Revenue-cap regime” is a type of incentives-based regime where the prices can be adjusted to recover any difference between the expected and realised volumes, i.e. volume risk is borne by customers .

“Risk-free rate” is a return required by an investor for an investment in a risk-free asset.

“Straight-line depreciation” refers to a depreciation profile whereby the annual depreciation expense is constant, typically over the lifespan of an asset.

“Sunk cost” means a cost that has already been incurred and is not recoverable.

“TD&R” means transmission, distribution and retail.

“TD&R licence” means a licence granted under section 25 of the Electricity Act 2016.

“Test Year” refers to a year, in the past, for which data is available, and is used to define future cost allowances.

"ToU" means time of use pricing or billing, whereby charges are based on how much energy is used and when the usage occurs.

"Transfer pricing arrangement" refers to an arrangement pursuant to which the TD&R business unit of a vertically integrated utility procures power from the generation business unit of a vertically integrated utility.

"True-up mechanism" means a mechanism which adjusts the cost allowances such that they align with the actual costs borne by a company.

"TSF" means tariff stabilisation fund, as described in paragraph 21 hereof.

"Vertically integrated utility" means a company that engages in bulk generation and transmission, distribution, and sale (retailing) of electricity.

"Vanilla WACC" means the weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity, as set forth in paragraph 55 of the Retail Tariff Methodology.

"Volume risk" means the risk that sold units of electricity deviate from the forecast.

"WACC" means weighted average cost of capital.

2 INTERPRETATION

(1) For purposes of interpreting this General Determination:

(a) unless the context otherwise requires, words or expressions shall have the meaning assigned to them by the RAA and the EA;

(b) where there is any conflict between the provisions of this General Determination and the EA or RAA, the provisions of the EA or RAA, as the case may be (and subject to sections 3(2) and 3(3) of the EA), shall prevail;

(c) terms defined herein and in the EA and RAA have been capitalised;

(d) headings and titles used herein are for reference only and shall not affect the interpretation or construction of this General Determination;

(e) references to any law or statutory instrument include any modification, re-enactment or legislative provisions substituted for the same;

(f) a document referred to herein shall be incorporated into and form part of this General Determination and a reference to such document is to the document as modified from time to time;

(g) expressions cognate with those used herein shall be construed accordingly;

(h) use of the word "include" or "including" is to be construed as being without limitation; and

(i) words importing the singular shall include the plural and vice versa, and words importing the whole shall be treated as including a reference to any part unless explicitly limited.

3 LEGISLATIVE AND PROCEDURAL BACKGROUND

(1) This General Determination has been undertaken in accordance with section 62 of the RAA and the exercise by the Authority of its powers under sections 6, 14, 17 and 35 of the EA.

(2) The Authority initiated the consultation by publishing a Consultation Document on 8 March 2018 that invited responses from members of the public, including electricity sectoral participants and sectoral providers, as well as other interested parties. The purpose of the Authority's initial Consultation Document was to consult on the proposed Retail Tariff Methodology.

(3) The Consultation Document asked questions on the following topics:

TD&R licensee

- Tariff design
- Form of control
- Building blocks of regulation
- Proposed remuneration of operation expenditure ("OPEX") of the TD&R licensee
- Initial asset valuation
- Rate base roll-forward
- Depreciation
- Capital expenditure
- Return of capital
- Outputs

Bulk Generation licensees

- Capacity fee-existing generation assets
- Capacity fee-new generation assets
- Energy fee
- Fuel adjustment rate
- Outputs

(4) The Consultation Document also invited respondents to comment on the structure of the proposed retail tariff methodology.

(5) Responses to the Consultation Document were solicited from the public electronically through the Authority's website at rab.bm.

(6) The response period commenced on 8 March 2018 and concluded on 19 April 2018.

(7) The Authority received three responses from the public.

(8) The Authority issued a Preliminary Report, Preliminary Decision and Order on 10 September 2018 that invited responses from members of the public, including electricity sectoral participants and sectoral providers, as well as other interested parties.

(9) The Authority received three responses from the public for the Preliminary Report, Preliminary Decision and Order.

4 FINAL DETERMINATION

(1) Pursuant to section 62 of the RAA and in accordance with sections 6, 14, 17 and 35 of the EA using the general powers granted to the Authority under section 13 of the RAA and in accordance with the procedures established for this purpose in section 62 of the RAA, the Authority hereby determines that:

(2) The adoption and implementation of the Retail Tariff Methodology as set forth in Annex 1 of this Schedule below is consistent with the purposes of the EA, including to seek to: (a) ensure the adequacy, safety, sustainability and reliability of electricity supply in Bermuda; (b) encourage electricity conservation and the efficient use of electricity; (c) promote the use of cleaner energy solutions and technologies; (d) provide sectoral participants and end-users with non-discriminatory interconnection to transmission and distribution systems; (e) protect the interests of end-users with respect to prices and affordability, and the adequacy, reliability and quality of electricity service; and (f) promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

ANNEX 1 – RETAIL TARIFF METHODOLOGY

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1. INTRODUCTION

1. The Regulatory Authority of Bermuda (the "Authority") is issuing this General Determination to establish the methodology for setting the Retail Tariff (the "Methodology") charged by the TD&R licensee to the electricity consumers in Bermuda.

2. This Methodology should be considered in combination with other regulatory tools, such as those listed below.

   a. **Integrated Resource Plan**—an energy plan for the supply of electricity in Bermuda. The IRP defines the requirements for the transmission, distribution and retail ("TD&R") licensee to meet forecasted energy demand using both supply- and demand-side resources to ensure reliable, cost-effective service to customers. The IRP includes a procurement plan that can be used to guide bulk generation licensees' capital expenditure ("CAPEX") forecast.

   a. **Net benefit test—**which provides the framework for assessing fair network access in Bermuda's electricity sector through balancing the benefits and costs of new generation capacity.

   b. **Power Purchase Agreement ("PPA") guidelines**—which facilitates and aids the negotiation of PPAs between the TD&R licensee and IPPs, to encourage efficient procurement of generation.

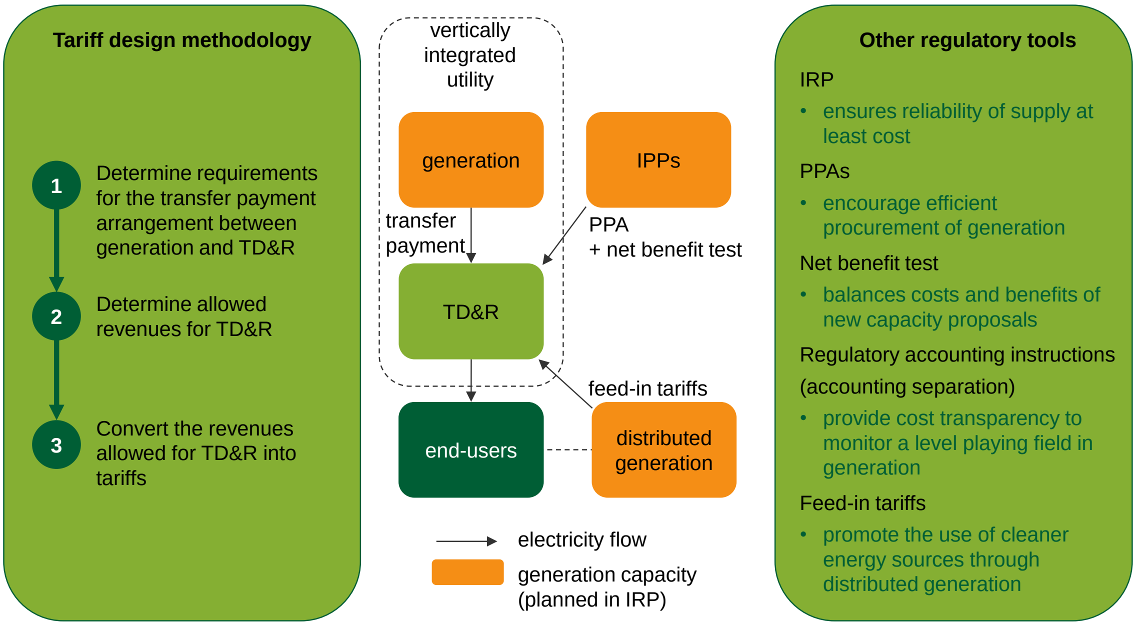
   c. **Regulatory accounting instructions**—which require separate regulatory accounts for the bulk generation and TD&R licensees. This informs the tariffs to end-users and provides cost transparency to monitor whether there is a level playing field in generation.

   d. **Feed-in tariff methodology**—setting the methodology to define the feed-in tariff — the pre-determined rate at which the TD&R licensee purchases renewable energy from distributed generators. The feed-in tariff methodology ensures that all electricity resources have access to transmission and distribution systems on fair, reasonable and non-discriminatory terms.

   e. **Service Standards—** which set key performance indicators for assessing the quality of customer service and the technical performance of the TD&R licensee and bulk generation licensees.

3. Figure 1.1 below illustrates the regulatory regime.

Figure 1.1 Elements of the regulatory regime



Note: IRP - Integrated Resource Plan; PPA - Power Purchase Agreement; IPP - Independent Power Pproducer and TD&R - Transmission, Distribution and Retail.

4. In particular, the Methodology introduces elements of incentive regulation to promote economic efficiency in the provision of electricity services to the customers of Bermuda. The Methodology determines the allowed revenue for the TD&R licensee, which is subsequently converted into retail tariffs.

5. The allowed revenue of the TD&R licensee is determined using the formula:

Allowed revenue = operating expenditure (“OPEX”) +
depreciation + rate base x return on rate base

6. The Methodology combines some elements of incentive regulation (i.e. ex ante cost forecasts) and some elements of rate-of-return regulation (cost pass-through allowances).

7. Table 1.1 below describes the treatment of each component of allowed revenue in turn.

Table 1.1 Treatment of the components of the allowed revenue for the TD&R licensee

Element of regulatory regime	Treatment
Rate base	• the components of the rate base are plant in service and working capital; construction work in progress is not included in the rate base • historical cost accounting approach for the initial valuation of assets and a periodic update of the rate base in accordance with the annual CAPEX (ex ante, subject to an asymmetric CAPEX incentive scheme) and depreciation
Depreciation	• straight-line depreciation, subject to approval of the asset-life assumptions
OPEX	• core network OPEX: ex ante, subject to an asymmetric incentive scheme • power procurement:* cost pass-through allowance • other expenses (fees and taxes): cost pass-through allowance
Return on rate base	• ex ante nominal vanilla WACC estimate, subject to a trigger mechanism[1]

Note: CAPEX, capital expenditure; OPEX, operating expenditure; WACC, weighted average cost of capital. * This includes a transfer payment to the generation business unit of the vertically integrated utility from the TD&R licensee.

8. The Authority considers that at this time, in the regulation of electricity, the degree of competition in the electricity generation market in Bermuda is not sufficient to ensure that the terms for the procurement of electricity would reflect the best available market terms. Therefore, the Methodology places certain requirements in relation to terms for the procurement of electricity.

9. In particular, the Authority provides a methodology for a transfer pricing arrangement for the vertically integrated utility, i.e. Bermuda Electric Light Company Limited ("BELCO"). Regarding any new generation facilities proposed by IPPs, the Authority will assess PPAs for such IPP entrants on a case-by-case basis and always with the intention of pursuing the purposes of the Electricity Act 2016 ("EA").

10. For both the TD&R licensee's transfer pricing arrangement with its bulk generation business unit and PPAs with IPPs, the Authority concludes that the charges to the TD&R licensee shall be sufficient to recover the sum of the bulk generation licensee's initial investment (including a return on invested capital), bulk generation licensee's ongoing costs, and its fuel costs. The exact terms of a PPA will be negotiated between the TD&R licensee and an IPP bilaterally, subject to the Authority's approval. The transfer pricing arrangement between the TD&R and bulk generation business units of a vertically integrated utility will be reviewed and approved by the Authority periodically, aligned with the review periods for the TD&R licensee.

11. Once the allowed revenue for the TD&R licensee is established, the total revenue must then be allocated across different customer classes and converted into retail tariffs.

12. The rest of this General Determination is structured as follows:

    a. Section 2 describes the approach to setting the allowed revenue for the TD&R licensee;

    b. Section 3 describes the requirements in relation to the transfer pricing arrangement between the TD&R and bulk generation business units of the vertically integrated utility;

    c. Section 4 describes the approach for converting the allowed revenue into appropriate retail tariffs; and

[1] Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and allowed ex ante for the duration of a review periodbut allowed to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate).

d. Section 5 summarises the Methodology.

2. PRINCIPLES OF THE REGULATORY DESIGN FOR THE TD&R LICENSEE

13. This section described the Methodology for setting the allowed revenue for the TD&R licensee.

II.A. **Form of Tariff Review**

14. The Authority considers that a hybrid of the two forms of tariff review, rate-of-return and incentive regulation, is the most appropriate regulatory regime for the TD&R licensee in Bermuda. This is to balance the provision of incentives to promote cost efficiency with proportionality and practicality of implementation. In particular, instead of using pure rate-of-return cost pass-through for all elements of the allowed revenue, the Methodology also includes some elements that are fixed ex ante at the level of the efficient cost forecast, i.e. similar to incentive regulation.

15. In addition, the Authority concludes that the TD&R licensee should be subject to a revenue-cap regime (where applicable).

16. The regime should be based on five-year review periods.[2] However, as the energy market in Bermuda is going through a period of change, the Authority considers that a transitional period with shorter review periods is appropriate. In particular, there will be a transitional period of up to five years. During this transitional period, the frequency and duration of tariff reviews will be determined by the Authority. After the initial transitional period, the Authority expects that the regulatory regime would be mature enough to support longer, five-year review periods. The TD&R licensee will also maintain the right to request that the Authority re-opens the tariff review if it has to incur unexpected costs that exceed 20% of the licensee's revenue. Similarly, the Authority maintains the right to re-open a tariff review if the TD&R licensee achieves a cost outperformance of at least 20% of its revenue.

17. In the rest of this section, the regulatory regime is described in detail.

II.B. **Building Blocks of Regulation**

18. Pursuant to the EA, the allowed revenue under both rate-of-return and incentive regulation regimes is set such that the TD&R licensee recovers reasonable costs in respect of efficiently incurred OPEX and CAPEX as well as the cost of capital.[3] This would be realised through the allowance of OPEX, depreciation and a return on capital (rate base x return on rate base). In broad terms, the allowed revenue is calculated in accordance with the following formula:

Allowed revenue = OPEX + depreciation + (rate base x return on rate base)

19. As such, the intention of the allowed revenue is to align the revenues of a regulated company with those that the company would expect to earn in a competitive market. Table 2.1 provides a summary of the Methodology. The rest of this section describes the treatment of each component in detail.

[2] The EA requires the retail tariff review to happen every five years or less. See Electricity Act 2016, section 37(1)(a).
[3] See Electricity Act 2016, section 35.

Table 2.1 Treatment of each component of allowed revenue for the TD&R licensee

Element of regulatory regime	**Treatment**
Rate base	• the components of the rate base are plant in service and working capital; construction work in progress is not included in the rate base • historical cost accounting approach for the initial valuation of assets and a periodic update of the rate base in accordance with the annual CAPEX (ex ante, subject to an asymmetric CAPEX incentive scheme) and depreciation
Depreciation	• straight-line depreciation, subject to approval of the asset-life assumptions
OPEX	• core network OPEX: ex ante, subject to an asymmetric incentive scheme • power procurement:* cost pass-through allowance • other expenses (fees and taxes): cost pass-through allowance
Return on rate base	• ex ante nominal vanilla WACC estimate, subject to a trigger mechanism[4]

Note: CAPEX, capital expenditure; OPEX, operating expenditure; WACC, weighted average cost of capital. * This includes a transfer payment from the TD&R licensee to the generation business unit of the vertically integrated utility.

20. As outlined above, the regime will be based on five-year review periods. However, a number of cost categories are subject to cost pass-through treatment—i.e. if actual costs incurred by the licensee are different from the ex ante allowance, then the regulatory regime would provide an adjustment to the allowed revenue in future periods such that the licensee recovers its costs in full. The Authority considers that such adjustments should be made on an annual basis, i.e. an annual true-up mechanism should be used. This approach allows a closer alignment between the revenues recovered and costs incurred by the licensee, and therefore helps to promote the economic sustainability of the electricity sector. In addition, an element of a frequent true-up mechanism should be maintained in the form of the fuel adjustment rate ("FAR"), which adjusts the total tariffs intra-year in order to reflect the changes in the fuel costs.

21. Under the previous regime, there is a different mechanism that ensures that the company's recoverable revenues are in line with costs that have been incurred. In particular, where actual profit is above the targeted level of profit, the difference accumulates within a fund, i.e. the TSF. The TSF is then used to defer tariff increases or to make up revenue requirement shortfalls similar to the FAR balancing account.[5]

22. Under the Methodology, the Authority concludes that the retention of the TSF mechanism is not necessary. Instead, for ease of implementation, adjustments for discrepancies between allowed expenditure and actual expenditure can be directly incorporated as an adjustment within regulatory allowed revenues in future periods. This is as per a true-up mechanism where the TD&R licensee would share the company's outperformance with customers. Moreover, the TSF mechanism constrains the level of actual profit that the company can achieve, and thereby lowers incentives to reduce costs.

23. Another fund, the National Disaster Contingency Fund (the "NDC Fund"), is required under Condition 17 of the TD&R license granted to BELCO.

24. The TD&R licensee does not currently have an NDC Fund. Instead, in order to protect itself against any natural disasters, the licensee has insurance coverage obtained from the market.[6] The cost of insurance coverage, if efficiently incurred, should be part of allowed OPEX and should therefore be recovered from customers via regulated tariffs. In order to provide additional protection against costs related to a national disaster, the TD&R licensee shall establish an NDC Fund. The source and methodology for funding and disbursing the NDC

[4] Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and allowed ex ante for the duration of a review periodbut allowed to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate).
[5] Energy Commission (2016), "Re: BELCO Base Rate Filings—June 3, 2015", 31 March, para. XXVII (b).
[6] Ascendant group (2018), 'Annual report 2017', p. 15.

Fund shall be established by the Authority. Moreover, an additional protection against unexpected costs is provided by allowing for the potential use of a ‘re-opener’ mechanism for the tariff review, in the event of significant and uncontrollable deviations (positive or negative) in actual costs relative to allowances. (see section II.C.).[7]

25. To the extent possible, the licenses and any general determinations shall be construed consistently. However, where any irreconcilable differences between licences and the Retail Tariff Design Methodology General Determination arise, the Retail Tariff Design Methodology General Determination would take precedence.

II.C. Operating Expenditure

26. In this section, the approach for remunerating OPEX for the TD&R licensee is described.

27. Previously, OPEX is remunerated on a cost pass-through basis, i.e. OPEX that is allowed to be recovered through tariffs is based on the actual costs incurred by the TD&R licensee. While this approach was transparent in its implementation, it did not provide sufficiently strong incentives for the licensed company to improve efficiency and deliver electricity services for the least cost.

28. In order to incentivise the TD&R licensee to improve efficiency, it would be appropriate to introduce ex ante OPEX allowances. The Authority distinguishes two potential approaches for remunerating OPEX on an ex ante basis:

e. **a top-down approach**—this would project the allowed OPEX over a review period based on the *aggregate* level of expenditure, i.e. the efficient level of overall OPEX for the company is assessed;

f. **a bottom-up approach**—this would project the allowed OPEX over a review period based on a more *disaggregated* level of expenditure, i.e. overall OPEX is built up from line-by-line cost projections.

29. Both approaches would require comprehensive engineering and benchmarking studies in order to project the efficient levels of OPEX.

30. Overall, the Authority expects that the TD&R licensee will use one of these approaches to prepare a well-justified OPEX forecast.

31. The Authority will divide the approach for remuneration of OPEX for the TD&R licensee across three distinct categories of expenditure—core network OPEX, procurement of power and other expenses (fees and taxes).

Core network OPEX

32. The Authority concludes that the OPEX allowance should be based on the forecast of the efficient costs submitted by the TD&R licensee and that the levels of forecast OPEX put forward by the TD&R licensee should be well justified.

33. The Authority recognises the difficulty in preparing a well-justified OPEX forecast. Therefore, the Authority considers it acceptable to benchmark the OPEX allowance to the “Test Year”, being the latest year for which data is available, for the first review period.

[7] Specifically, where the licensee has to incur unexpected costs, or achieves cost savings, which exceed 20% of its revenue, the tariff may be re-opened.

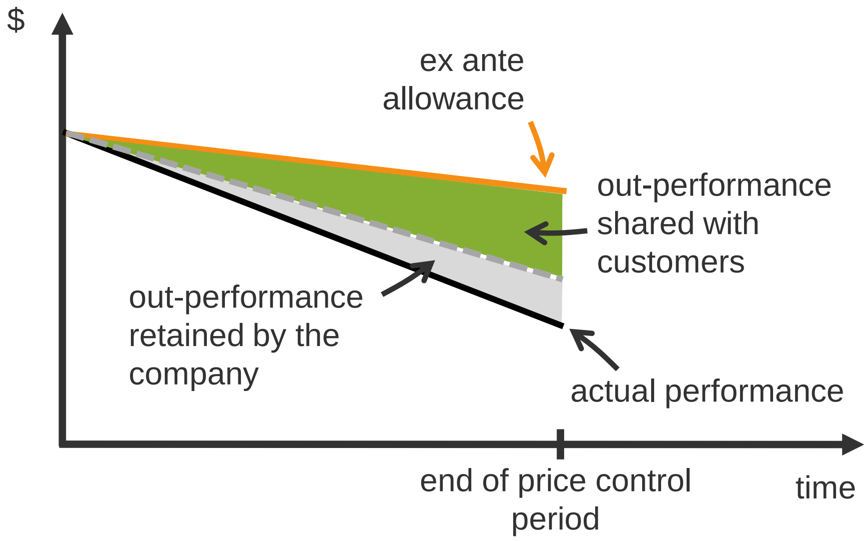
34. In addition, an asymmetric incentive mechanism for the actual OPEX incurred by the TD&R licensee should be used, such that:

g. should the TD&R licensee incur OPEX below the ex ante allowance, the outperformance should be shared by the TD&R licensee with the customers and/or the NDC Fund on a 20:80 basis (i.e. the majority of the benefit accrues to customers and/or the NDC Fund, the proportional split to be determined by the Authority); and

h. should the TD&R licensee incur OPEX in excess of the ex ante allowance, the cost of the underperformance should be absorbed by the TD&R licensee.

35. This illustrated in Figure 2.1 below.

Figure 2.1 OPEX remuneration mechanisms



Power procurement

36. Pursuant to sections 47 and 48 of the EA and condition 24 of the TD&R license, procurement of power by the TD&R licensee shall be effected under:

i. an Authority approved PPA between the TD&R licensee and an IPP;[8] and

j. a power purchase arrangement ("transfer pricing arrangement") between the TD&R license and the generation business unit of the vertically integrated utility.

37. In the short term, the TD&R licensee will procure most of the power from its bulk generation business unit under a transfer pricing arrangement.

38. The cost of power procured should be remunerated within the TD&R licensee's allowed revenue on a cost pass-through basis.

Other Expenses (fees and taxes)

[8] A PPA secures the payment stream and specifies agreed terms and conditions for a project undertaken by an IPP. It is usually agreed between the purchaser ("offtaker") and a privately-owned power producer. In addition to obligations relating to the sale and purchase of the power generated, the PPA also sets out the required design and outputs and operation and maintenance specifications for the power plant. Source: World Bank (2017), Power Purchase Agreements (PPAs) and Energy Purchase Agreements (EPAs), https://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements.

39. Compensation for any fees, charges or taxes that the TD&R licensee is obliged to pay to public authorities (except for fines and penalties) should be compensated on a cost pass-through basis.

40. The approach for the remuneration of OPEX is summarised in Table 3.1.

Table 3.1 OPEX remuneration summary

Type of TD&R costs	Approach
Core network OPEX	• ex ante, subject to an asymmetric incentive scheme
Power procurement*	• cost pass-through allowance
Other expenses (fees and taxes)	• cost pass-through allowance

Note: * This includes the transfer pricing arrangement for the vertically integrated utility.

II.D. Rate Base

41. Rate base is a driver of the return *on* capital (i.e. allowed profit), and the return *of* capital (i.e. depreciation). The rate base shall be determined using the following principles.

a. **Components of the rate base**—plant in service and working capital are the components of the rate base. Construction work in progress ("CWIP") is not included in the rate base.[9] This is discussed in section II.D.1.

b. **Initial asset valuation**—the assets should be valued using historical cost accounting ("HCA") approach.

c. **Rate base roll-forward**—the rate base should be updated using HCA values of CAPEX and depreciation that will be directly observable in the regulatory accounts.

d. **Depreciation**—a straight-line depreciation approach should be applied to the TD&R licensee's rate base in order to estimate the depreciation allowance. The Authority will approve the asset-life assumptions used in regulation and, where assumptions change, may disagree with a change and base the allowed revenue calculations on the asset-life assumptions that the Authority considers appropriate.

e. **CAPEX**—introduce an asymmetric CAPEX incentive scheme for the TD&R licensee. This is discussed in section II.D.2.

42. The rest of the section defines the components of the rate base (section II.D.1) and treatment of CAPEX (section II.D.2).

II.D.1 Components of the rate base

43. The rate base is the value of the assets on which investors earn a return. The rate base will include:

f. plant in service—typically equivalent to the fixed assets that are used and useful to generate revenue;

g. working capital—typically including materials and supplies, fuels and lubricants (these items are applicable to a bulk generation licensee only) and cash working capital (i.e. cash requirements for a timing lag between cash inflows and outflows);

[9] The Authority notes that adjustments may be required to the book values of the above components for the purpose of assessing regulatory allowed revenues.

44. It is important that there is no double counting in regulatory allowed revenues; for example, if an unspent OPEX allowance is recorded as a current asset (e.g. as excess cash or excess inventory stock) within the calculation of working capital and then included in the rate base, then the allowance would be double counted. To avoid double counting, as part of the tariff review, the Authority will review the allowance for working capital carefully. In any case, working capital that is included in the rate base will not earn a depreciation component of allowed revenue. The Authority will also consider whether it would be appropriate to allow a differentiated rate of return on capital to be earned, on the working capital component of the rate base.

45. The CWIP should not be included in the rate base to ensure consistency of the Methodology with section 35 (2) (a) of the EA where the EA states that the investment cost should be recovered only where it is used and useful.

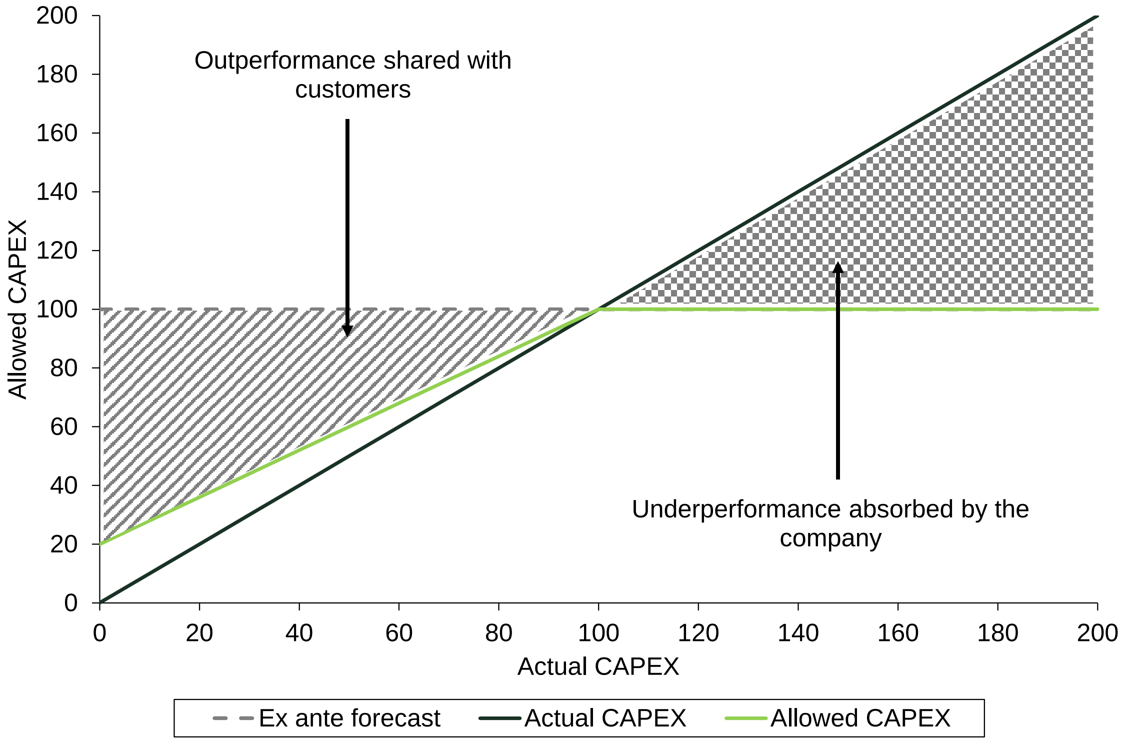
II.D.2. Capital expenditure

46. CAPEX plans of the TD&R licensee shall be subject to scrutiny, whereby, inter alia, the TD&R licensee will be required to commit to the amount, timing, scope and specification of the proposed capital programme. As a result, CAPEX shall be subject to an ex ante incentive scheme.

47. An incentive scheme would be structured in such a way that it encourages the TD&R licensee to become more efficient and reveal its best estimates of the costs. This will be achieved through an asymmetric incentive, where the TD&R licensee bears the cost of CAPEX overspend relative to the ex ante allowance but shares the benefit of outperformance with its customers. The investment and financing plans will be used to determine the ex ante allowance. Should the TD&R licensee not achieve any of the timing, scope or specification commitments, a penalty and reward scheme can be applied.

48. Such an incentive scheme is illustrated in Figure 3..

Figure 3.1 Asymmetric CAPEX incentive scheme



Note: The TD&R licensee is assumed to bear the full cost of overspend relative to the ex ante allowance and to share any outperformance with its customers and/or the NDC Fund on a 20:80 basis (i.e. the majority of the benefit accrues to customers and/or the NDC Fund).

49. The asymmetric CAPEX incentive scheme outlined above should provide strong incentives for the TD&R licensee to deliver proposed CAPEX at the least cost.

50. Once the capital programme is delivered and the Authority concludes that the allowed revenue for the future years may be adjusted such that any overspend relative to the initial plan will be subject to a “claw back”, i.e.:

h. if actual CAPEX exceeds the ex ante capital plan forecast, the TD&R licensee bears the full cost of overspend;

i. if actual CAPEX is below the ex ante capital plan forecast, the TD&R licensee shares the benefit of the outperformance with customers and/or the NDC Fund on a 20:80 basis (i.e. the majority of the benefit accrues to customers and/or the NDC Fund).

51. In addition, the Authority may consider the use of specific and targeted ex post adjustments in relation to allowed CAPEX, where there is evidence that CAPEX has been inefficiently accrued or specification of the delivered capital programme deviates from the initial plan without appropriate justification.

II.D.3. Summary of the approach for setting the rate base

52. Table summarises the approach for establishing and updating the rate base.

Table 4.1 Summary of the approach for setting the rate base

Issue	Approach
Components of rate base	Plant in service and working capital; CWIP is not included in the rate base
Initial asset valuation	Net book value of the assets based on HCA accounts
Rate base roll-forward	HCA approach for rate base roll-forward
Depreciation	Straight-line depreciation
CAPEX	Ex ante, subject to an asymmetric CAPEX incentive scheme

53. The net book value of the components of the rate base can be used to determine the value of the rate base. However, if the Authority disallows some CAPEX due to an asymmetric CAPEX incentive scheme, then the adjustments would need to be applied to the net book value of the components of the rate base.

II.E. Return on Capital

54. The allowed rate of return on capital needs to be sufficient for the regulated company to recover its cost of capital. In particular, it needs to allow an appropriate return to equity holders—i.e. cost of equity, and to cover the company's interest expense payable to its creditors—i.e. cost of debt. Therefore, an appropriate approach to estimate the allowed rate of return is to calculate the weighted average cost of capital ("WACC") of the licensee(s).

55. The vanilla WACC, which is defined with the following formula, should be used:

WACC = cost of equity * (1 – gearing) + cost of debt * gearing

where gearing is the share of debt in a company's total capital.[10]

56. Where vanilla WACC is used for remuneration of return on capital, all taxes are accounted for as part of OPEX allowances.[11]

57. WACC should be calculated on a nominal basis. This is consistent with the current base-rate filing system requirements.[12]

58. The main components of the WACC—cost of equity, cost of debt, and gearing—are discussed in turn below.

II.E.1. Cost of equity

59. The cost of equity is the return required by a company's shareholders. The Authority concludes it appropriate for the TD&R licensee to apply multiple methodologies to estimate the range for the cost of equity. These may, for example, include the CAPM, the discounted cash flow approach or a risk-premium approach. Based on the range of evidence, the Authority will make the final decision regarding the point estimate for the cost of equity allowance.

II.E.2. Cost of debt and gearing

60. The Authority will choose the cost of debt that strikes the right balance between retaining the incentives for an entity to manage its risks in an efficient manner and to ensure that the entity

[10] Gearing is defined as the ratio of a company's net debt to the rate base. Net debt is a company's total debt and liabilities after subtracting its cash and cash equivalents.
[11] Note that there is no corporate tax in Bermuda. Ascendant Group Limited (2015), Annual report 2015, p. 35.
[12] NERA Economic Consulting (2015), BELCO Cost of Capital. Exhibit 2.0, 21 May, https://www.gov.bm/sites/default/files/BELCO%20Base%20Rate%20Filing%20030615.pdf.

would be able to attract needed capital.[13] Both conditions need to be satisfied to ensure reliability of the provided service.

61. With this in mind, the Authority considers that the cost of debt should be estimated on the basis of a notional, efficiently financed entity. For ease of implementation, the cost of debt of a generation business unit may be allowed to be the same as for the TD&R business unit, as it is likely that the licensee will raise debt at the entity level, i.e. for both TD&R and generation.

62. In line with the cost of debt, the gearing estimate should be set at the notional level. The gearing of a generation business unit may be allowed to be the same as for the TD&R business unit as it is likely that the licensee will raise debt at the entity level, i.e. for both TD&R and generation.

63. To take account of the unique capital market constraints in Bermuda, the Authority concludes that it is appropriate for the first tariff review to be informed, in the determination of the notional gearing and cost of debt, by the expected capital structure and financing options available to the licensee. The Authority notes, however, that the licensee would need to justify the choice of its target capital structure and provide evidence showing that debt, if any, would be raised on market terms.[14]

II.E.3. Other considerations

64. Given the changing market environment, it may be challenging to forecast a cost of capital for the review period. To account for interest-rate uncertainty and to mitigate the risk that an entity will be unable to raise the required capital, the Authority introduces a trigger mechanism. Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and permitted ex ante for the duration of a review period but permitted to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate). In addition, the gearing and cost-of-debt assumptions should be reassessed when the licensee undertakes significant changes to its capital structure. This would provide the incentives and simplicity of the ex ante fixed-rate approach while allowing for revision of the allowed return in “extreme” market volatility scenarios and under significant changes in circumstances.

II.E.4. Summary of the approach for setting the return on capital

65. Table summarises the approach for estimating the appropriate return on capital.

Table 5.1 Summary of the approach for setting the return on capital

Component	**Approach**
Cost of equity	Fixed for the duration of a review period with a trigger mechanism.
Cost of debt	Fixed for the duration of a review periodat a notional level subject to revision when significant changes to capital structure occur. The first tariff reviewto be informed, in the determination of the notional gearing and cost of debt, by the expected financing options available to the licensee.
Gearing	Fixed for the duration of a review periodat a notional level subject to revision when significant changes to capital structure occur. The first tariff review to be informed, in the determination of the notional gearing and cost of debt, by the expected capital structure of the licensee.

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[13] The latter is referred to as a financing duty of a regulator and is required by section 35 (2) (b) of the EA.
[14] Examples of evidence that the Authority would expect from BELCO include existing financing agreements with evidence of competitive offers, or yields of bonds with a comparable credit rating, if credit rating analysis is undertaken.

II.F. **Outputs**

66. A defined set of specific outputs would provide incentives for the TD&R licensee to deliver the services that consumers require. The Authority shall set specific outputs that the TD&R licensee should deliver in accordance with the process set by general determination pursuant to section 34 of the EA. These outputs may include generation availability of generation capacity, network reliability and efficiency, customer satisfaction and safety. The Authority considers that some of these metrics may be monitored both on an average basis as well as on "worst-served customer" basis. The latter would facilitate an understanding of the distribution of outcomes across customers and create an incentive to target improvement for the worst-served customers.

67. In addition, the Authority will consider that financial penalties could be associated with some of the outputs (and the relevant metrics). Specifically, if the TD&R licensee does not achieve a predefined level of performance, then it will face a reduction in the levels of its allowed revenue.

68. However, it may not be possible to establish binding targets in a timely manner for the purpose of the first tariff review. Therefore, the TD&R licensee should monitor the relevant metrics over the first review period with a view to incorporating binding performance thresholds in future tariff reviews.

3. PRINCIPLES OF THE REGULATORY DESIGN FOR THE BULK GENERATION LICENSEE(S)

69. Pursuant to sections 47 and 48 of the EA and condition 24 of the TD&R license, procurement of power by the TD&R licensee shall be effected under:

    a. an Authority approved PPA between the TD&R licensee and an IPP;[15] and

    b. a power purchase arrangement ("transfer pricing arrangement") between the TD&R license and the generation business unit of the vertically integrated utility.

70. Any PPA should be consistent with the IRP, the purposes of the EA and any Ministerial directions, and that it "does not create risks to power quality or reliability, or unreasonable financial risks for the TD&R licensee", as required by sections 47 and 48 of the EA.[16] In addition, the terms of the transfer pricing arrangement between the TD&R licensee and its bulk generation business unit should be substantially similar to the terms of a PPA between the TD&R licensee and an IPP.

71. For both the transfer pricing arrangement and a PPA, the charges to the TD&R licensee should be sufficient to recover the sum of the bulk generation licensee's initial investment (including a return on invested capital), bulk generation licensee's ongoing costs, and its fuel costs.

72. While the exact terms of a PPA will be negotiated between the TD&R licensee and an IPP bilaterally, subject to the Authority's approval, the transfer pricing arrangement between the TD&R licensee and its generation business unit shall be subject to economic regulation. In particular, the approach to the economic regulation is summarised in Table 7.1 below.

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[15] A PPA secures the payment stream and specifies agreed terms and conditions for a project undertaken by an IPP. It is usually agreed between the purchaser ("offtaker") and a privately-owned power producer. In addition to obligations relating to the sale and purchase of the power generated, the PPA also sets out the required design and outputs and operation and maintenance specifications for the power plant. Source: World Bank (2017), Power Purchase Agreements (PPAs) and Energy Purchase Agreements (EPAs), https://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements.

[16] Electricity Act 2016, section 48 (3).

Table 7.1 Bulk generation licensee’s costs remuneration summary

Element of regulatory regime	Approach
Volume risk	• price-cap regime
Duration of the review period	• aligned with the review periods for the TD&R licensee
Re-opener	• if the licensee has to incur unexpected costs or achieves cost savings that exceed 20% of its revenue, the tariff review can be re-opened
Components of transfer payment	• total transfer payment would be calculated as OPEX (excluding fuel) + fuel adjustment rate + depreciation + rate base x return on capital
Rate base	• the components of the rate base are plant in service and working capital; construction work in progress is not included in the rate base • historical cost accounting approach for the initial valuation of assets and a periodic update of the rate base in accordance with the annual CAPEX (ex ante, subject to an asymmetric CAPEX incentive scheme) and depreciation
Depreciation	• straight-line depreciation, subject to approval of the asset-life assumptions
Operating expenditure (excluding fuel)	• ex ante, subject to an asymmetric incentive scheme
Fuel adjustment rate	• retain the FAR mechanism, subject to a number of changes (section III.D)
Return on capital	• consistent with the methodology used for the TD&R licensee (section II.E).
Outputs	• metrics to monitor safety, reliability and generation efficiency

Note: Although the FAR mechanism is specified as part of the Methodology, the TD&R licensee is required to reflect the FAR separately on a customer bill.

73. The transfer pricing arrangement shall be reviewed periodically, aligned with the review periods for the TD&R licensee.

74. Additionally, the overall charges under the transfer pricing arrangement shall be based on a price-cap regime.

75. The rest of this section discusses the elements of the transfer pricing arrangement.

III.A. Rate base

76. The rate base shall be determined using the following principles.

a. **Components of rate base**—the rate base for the bulk generation licensee shall cover the same components as the rate base for the TD&R licensee. See section II.D.1 for further discussion.

b. **Initial asset valuation**—the assets shall be valued using the historical cost accounting (“HCA”) approach.

c. **Rate base roll-forward**—the rate base shall be updated using HCA values of CAPEX and depreciation that will be directly observable in the regulatory accounts.

d. **Depreciation**—a straight-line depreciation approach shall be applied to the bulk generation licensee’s rate base in order to estimate the depreciation allowance. The Authority will approve the asset-life assumptions used in regulation and, where assumptions change, may disagree with a change and base the allowed revenue calculations on the asset-life assumptions that the Authority considers appropriate.

e. **CAPEX**—the same asymmetric CAPEX incentive scheme shall be introduced for the bulk generation licensee as for the TD&R licensee. This is to achieve one of the purpose of the

EA to encourage economic efficiency in the generation, transmission, distribution and sale of electricity.[17]

III.B. Return on capital

77. The return on capital shall be based on the methodology described in section II.E hereto. The return on capital shall be reviewed by the Authority periodically, aligned with the review periods for the TD&R licensee.

III.C. Operating expenditure

78. The same asymmetric OPEX incentive scheme shall apply to the bulk generation licensee as for the TD&R licensee.

III.D. Fuel Adjustment Rate

79. The FAR adjusts the total tariffs in order to reflect the cost of fuel.

80. The FAR mechanism shall be retained in the tariff-setting methodology, i.e. the tariffs should be adjusted periodically to reflect the changes in the fuel costs.[18] The mechanism is as follows:

   a. **Review the FAR quarterly rather than monthly**

   b. **Exclude the "Electricity Purchased" component from the FAR mechanism.** Under the Methodology, the FAR shall be a component of a PPA between the TD&R licensee and a bulk generation licensee, so the "Electricity Purchased" component is excluded from the FAR mechanism and subject to a separate cost pass-through by the TD&R licensee.

   c. **Remunerate entire fuel cost through FAR mechanism.** Rather than setting the FAR as an allowance for incremental costs that are incurred in line with moving wholesale costs in excess of $30 per barrel, the TD&R licensee shall recover the entire fuel cost through the FAR mechanism.

III.E. Outputs

81. Bulk generation licensee(s) shall be required to ensure safety, reliability and efficiency of generation. The Authority shall set the metrics that should be used to target individual outputs in accordance with the process set by general determination pursuant to section 34 of the EA.The Authority considers that different generation plants of the vertically integrated utility may target different values for these metrics, e.g. to account for different expected performance.

82. In addition, the Authority will consider that financial penalties could be associated with some of the outputs (and the relevant metrics). Specifically, if a bulk generation licensee does not achieve a predefined level of performance, then it will face a reduction in the levels of the allowed revenue.

83. However, the Authority considers that it may not be possible to establish binding targets in a timely manner for the purpose of the first tariff review. Therefore, bulk generation licensee(s) should monitor the relevant metrics over the first review period with a view to incorporating binding performance thresholds in future tariff reviews.

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[17] See Electricity Act 2016, section 6(f).

[18] Although the FAR mechanism is specified as part of the Methodology, the TD&R licensee is required to reflect the FAR separately on a customer bill.

4. TARIFF DESIGN

84. Section 2 outlines a framework to calculate the allowed revenue for the TD&R licensee, including the recovery of costs in relation to procuring electricity from bulk generation licensee(s).

85. In relation to the methodology to convert the allowed revenue into retail tariffs, the Authority considers that the TD&R licensee shall continue to bear the responsibility for calculating the precise tariff rates, subject to approval by the Authority. The tariff structure will be reviewed by the Authority periodically.

5. SUMMARY

86. The tariffs regime seeks to ensure that the purposes of the EA are met, changes to the regulatory regimes for both the TD&R and bulk generation licensee(s)[19]. Table 9.1 summarises the regime.

Table 9.1 Overview of the retail tariffs methodology

Element of the Methodology		Regulatory treatment
Form of review of the TD&R licensee		
1.	**Form of review**	**Combination of rate-of-return and incentives regulation.** This approach balances the provision of incentives to promote cost efficiency with proportionality and practicality of implementation.
2.	**Volume risk**	**Revenue-cap regime.** Under a revenue-cap regime, the TD&R licensee does not bear volume risk (i.e. the volume risk is borne by consumers). An alternative price-cap regime would incentivise the TD&R licensee to sell more electricity, which may be considered to be against the purposes of the EA.
3.	**Duration of the review period**	**Five-year review periods, with a transitional period.** Five-year review periods provide the licensee enough time to improve efficiency over the period of the tariff review. Since the energy market in Bermuda is going through a period of change, the duration of the review periods should be increased gradually over several price-review cycles.
Building blocks of regulation for TD&R licensee		
4.	**Treatment of cost pass-through allowances**	**Annual true-up mechanism for cost pass-through allowances.** This approach allows a closer alignment between the revenues recovered and costs incurred by a licensee, and therefore helps to achieve the economic sustainability of the electricity sector.
5.	**Core network OPEX**	**Ex ante allowance subject to asymmetric incentive mechanism.** The Authority expects that the TD&R licensee will use either top-down or bottom-up approaches to prepare a well-justified OPEX forecast. In addition, an incentive scheme where the TD&R licensee bears the cost of OPEX overspend relative to the ex ante allowance but shares the benefit of outperformance with its customers should be used.
6.	**Power procurement**	**Cost pass-through allowances.**
7.	**Other expenses incurred by the TD&R licensee**	**Cost pass-through allowances.** Compensation for any fees, charges or taxes that the licensees are obliged to pay to public authorities should be compensated on a cost pass-through basis (excluding fines or penalties).
8.	**Components of rate base**	Plant in service (typically equivalent to the fixed assets that are used and useful to generate revenue) and working capital (typically includes materials and supplies, fuels and lubricants—applicable to the bulk generation licensee only—and cash working capital); CWIP (construction work in progress) is not included in the rate base.
9.	**Initial asset valuation**	**HCA approach.** Retaining the HCA approach for the initial valuation of the vertically integrated utility's assets—split between the bulk generation and TD&R business units—in the interests of transparency and consistency with the current approach.
10.	**Rate base roll-forward**	**HCA approach.** This approach is preferred due its transparency and consistency with the current approach.
11.	**Depreciation**	**Straight-line depreciation.** A straight-line depreciation approach should be applied to the TD&R licensee's rate base in order to estimate the depreciation allowance.

[19] See Electricity Act 2016, section 6 for the purpose of the Electricity Act.

12.	**Asset lives**	**Economic lives.** It is important that only the economic lives of assets are used for their depreciation. The Authority should have a right to rebase the allowed revenue calculations on revised asset-life assumptions if the Authority considers that current asset-life assumptions made by the licensee are unreasonable.
13.	**Capital expenditure**	**Ex ante allowance subject to asymmetric incentive mechanism.** An incentive scheme should be used where the TD&R licensee bears the cost of CAPEX overspend relative to the ex ante allowance but shares the benefit of outperformance with its customers.
14.	**Return on capital**	**Nominal vanilla WACC.** As the HCA approach is used for establishing the rate base, the WACC should be calculated on a nominal basis. This is consistent with the current base-rate filing system requirements. Where vanilla WACC is used for remuneration of return on capital, all taxes (if any) are accounted for as part of OPEX allowances.
	a. Cost of equity	**Multiple methodologies.** TD&R licensee may apply multiple methodologies to estimate the range for the cost of equity. Based on the range of evidence, the Authority will make the final decision regarding the point estimate for the cost of equity allowance.
	b. Cost of debt and gearing	**Notional cost of debt.** The determination of the allowed cost of debt and allowed capital structure will be on a notional basis. This is because customers should not pay for an inefficient choice of capital structure. To take account of the unique capital market constraints in Bermuda, the Authority considers it appropriate for the first tariff review to be informed, in the determination of the notional gearing and cost of debt, by the expected capital structure and financing options available to the licensee.
	c. Interest-rate uncertainty	**Trigger mechanism.** Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and allowed ex ante for the duration of a review periodbut allowed to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate).
15.	**Outputs**	A number of metrics should be used to monitor the TD&R licensee's performance in relation to availability of generation capacity, network reliability, network efficiency, safety and customer satisfaction.
Regulatory design for bulk generation licensee(s)		
16.	**Volume risk**	**Price-cap regime.** In line with a typical charging structure between networks and independent generators, the overall charges under the transfer pricing arrangement should be based on a price-cap regime.
17.	**Duration of the review period**	**Five-year review periods, with a transitional period.** The duration of the review periods should be aligned with the review periods for the TD&R licensee.
18.	**Components of transfer payment**	**Building blocks**. The total transfer payment should be determined similarly to the allowed revenue for the TD&R licensee. Specifically, this would consist of OPEX (excluding fuel), fuel adjustment rate, depreciation and rate base multiplied by return on capital. The treatment of the components of the transfer payment with that of the TD&R licensee is aligned.
	a. Fuel adjustment rate	The FAR mechanism is maintained, subject to a number of changes. The TD&R licensee is required to reflect the FAR separately on a customer bill.
19.	**Outputs**	The definition of specific outputs would provide incentives for the bulk generation licensee to deliver the services that consumers require. The required outputs for the bulk generation licensee are **safety, reliability and efficiency** of generation. Metrics that should be used to monitor the bulk generation licensee(s') performance in relation to the required outputs.
Tariff design		

20. Approach to tariff design	TD&R licensee should continue to bear the responsibility for calculating the precise tariff rates, subject to approval by the Authority. The tariff structure will be reviewed by the Authority periodically.

ANNEX 1.1: TARIFF DESIGN

A TARIFF DESIGN

87. This section is structured as follows:

a. section A1 provides an overview of tariff design principles;

b. section A2 outlines different options for tariff design relevant to the electricity retail market in Bermuda.

A1 Principles Of Tariff Design

88. Principles of tariff design have been assessed in academic literature.[20] Specifically, a tariff should be designed such that the tariffs are:

a. yielding total revenue requirements;

b. achieving fairness in allocating total cost of service among different customers;

c. discouraging wasteful use of service;

d. ensuring revenue stability and predictability;

e. ensuring tariff stability and predictability; and

f. promoting simplicity, comprehensibility, public acceptability and feasibility of tariffs.

89. In this section, the Authority describes and evaluates these principles before applying them to the retail tariff design for the electricity sector in Bermuda.

a. Yielding Total Revenue Requirements

90. Ensuring that the tariff design yields the allowed revenue for the TD&R licensee is the primary objective of tariff design. The Authority proposed Methodology to calculate the allowed revenue for the TD&R licensee captures the total costs of the provision of the electricity service. Therefore, its approach is consistent with the EA, which requires the retail tariff to facilitate the recovery of costs for the TD&R licensee.

b. Fairness in allocating total cost of service among different customers

91. There are two main aspects to fairness in the context of tariff setting.

a. The first is cost-related fairness, i.e. ensuring that users pay based on the services they actually use and the costs that they directly impose. Electricity service customers are typically divided into classes, with the intention of grouping customers with broadly similar demand and cost characteristics. Customers within groupings with similar demand characteristics should then pay similar charges.[21]

b. The second is distributional fairness, which may be concerned with ensuring equality of access to electricity, and in particular ensuring that electricity is equally affordable for different customers. This may lead to cross-subsidisation across customers or customer classes. Distributional fairness takes into account considerations other than costs to serve in the tariff-setting process.

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[20] See, for example, Bonbright, J. (1961), *Principles of Public Utility Rates,* New York, Columbia University Press.

[21] It should be noted that pricing customers based on an exact calculation of their individual costs would be an extremely difficult exercise. Supplying electricity to thousands of customers in different locations is essentially the supply of thousands of different *products.* See Bonbright, J. (1961), *Principles of Public Utility Rates,* New York, Columbia University Press, p. 296.

92. Cost-related fairness and distributional fairness, while not mutually exclusive, may conflict to the extent that distributional fairness requires that tariffs are not fully cost-reflective.

c. **Discouraging wasteful use of service**

93. Central to the discouragement of wasteful use of the electricity service is economic efficiency, which is concerned with providing incentives for the efficient use of electricity in terms of the amount used and the timing of use. Efficiency in this case is therefore related to the encouragement of energy conservation. Typically, this will involve creating some disincentive for energy use, for example in the form of high per-unit charges or unit charges that increase with usage. In assessing the relevance of price-based efficiency incentives, it is important to consider how responsive customers are to changes in price. If they are price-insensitive (or have “inelastic” demand), there may be few benefits from price incentives. However, if customers differ in their price sensitivity, this may suggest different tariff structures for different customer types.

94. In economic theory, a key consideration is that the price that is set for electricity is reflective of the cost of producing an extra unit of electricity, that is, the marginal cost (“MC”) of an additional unit of electricity.[22] The MC comprises elements such as the marginal cost of fuel, capital and labour, as well as other production costs. The concept of setting prices to reflect MC is fundamental to efficient price signals. By pricing electricity with reference to MC, customers face a price that reflects the cost implications of increasing demand and the cost saving that would arise if they reduced demand. It therefore induces customers to adjust their usage to the point where the benefit to them would be outweighed by the change in costs if they were to further increase their consumption.

95. In practice, while economic efficiency is desirable, there are two crucial caveats. The first is that economic efficiency needs to be balanced with considerations related to fairness: there is nothing inherently fair about an economically efficient state of affairs. The second is that pricing purely to reflect MC will not facilitate full recovery of allowed revenue, because, among other things, there are elements of the allowed revenue that are due to large fixed costs in network businesses.

d. **Ensuring revenue stability and predictability**

96. In the electricity sector, demand from year to year is fairly predictable when compared with many other sectors. An electricity company typically has a high proportion of fixed costs and would therefore prefer to have predictable and stable cash flows. As a result, a company may prefer to have a higher proportion of its revenues generated from fixed charges rather than per-unit charges (higher fixed charges, relative to per-unit charges, result in greater revenue certainty). In addition, capacity or demand charges (discussed in section 0) introduce an element of revenue certainty.

e. **Ensuring tariff stability and predictability**

97. In general, consumers also prefer stability in their bills rather than frequent changes over time. Introducing significant changes to the tariff structure is undesirable on this principle.

f. **Simplicity, comprehensibility, public acceptability and feasibility of tariffs**

98. Tariffs should be simple and easy to understand. This is likely to entail the retention of certain cross-subsidies to a degree, since full cost reflection in all dimensions may result in overly complex tariff structures that are difficult to understand. Moreover, the more complex a tariff structure is, the less feasible its implementation.

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[22] Borenstein, S. (2016), The economics of fixed cost recovery by utilities, *The Electricity Journal*, **29**:7, pp. 5–12.

A2 Tariff Options

99. Based on the principles of tariff design described above, the Authority explores four main options for structuring tariffs in Bermuda:

a. **Peak tariffs** — involving pricing energy consumption differently during well-defined times of high demand and/or low supply;

b. **Two-part tariffs** — comprising both a fixed charge and a per-unit charge. The fixed charge (or "standing charge") may vary according to either consumer peak demand or average electricity usage;[23]

c. **Three-part tariffs** — similar to two-part tariffs, but with the addition of a fixed charge that is the same across all users;

d. **Block tariffs** — per-unit charges depend on the actual consumption.

100. These options are not mutually exclusive and, in practice, are often used in conjunction; the current tariff structure in Bermuda balances these elements.

a. Peak tariffs

101. Peak pricing involves pricing energy consumption differently during well-defined times of high demand and/or low supply. Such tariffs are readily justified for customers whose demands for electricity vary greatly by day, hour, week, month or season, and thus impose extra costs on various parts of the electricity supply system.

102. With peak pricing, users are charged a higher per-unit charge for access to the peak period (e.g. during the summer due to air conditioners). There are two main objectives of such a scheme:

a. cost reflection—to ensure that customers, at specified times, are charged for the impact of their high-intensity demand on system costs; and

b. incentives at the margin—to provide customers with high-intensity demand with an incentive to reduce their peak consumption.

103. Peak pricing is, therefore, a form of MC pricing: the per-unit charge levied during peak times should reflect the costs of electricity supply incurred in these time periods. As a result, peak pricing promotes cost-related fairness, since those users who require electricity during peak times (thereby imposing higher costs on the system) are charged higher tariffs for this usage.

b. Two-part tariffs

104. Two-part tariffs are a common tariff design used for customer electricity pricing. They are known as "two-part" because they are composed of a per-unit charge and a fixed charge.

105. The per-unit charge typically consists of a per-unit (kWh) charge for energy, intended to reflect the marginal cost of extra units of energy (however, there is some flexibility here—see "block tariffs" below).

106. The fixed charge component is typically intended to capture a customer's share of the fixed costs involved in supplying them with electricity, including the costs of transmission and

[23] There are, in practice, several variants of two-part tariffs. For instance, in the UK, a two-part tariff most commonly comprises an invariant or fixed 'standing charge', charged on a per-day basis (rather than being based on peak demand or average usage as defined above). Each unit of electricity used is then billed on a per-kWh basis. The present definitions are the most relevant to the actual charging structures currently in place in Bermuda.

distribution. By charging a fixed charge, the tariff is better able to recover allowed revenues while the incentive benefits of MC pricing are retained.

107. The fixed charge would usually vary according to either consumer peak demand or average electricity usage (hence, it is sometimes known as a "semi-fixed" charge). Charges based on peak demand are known as capacity charges and are often used for larger electricity users.24

108. From the point of view of cost recovery, a two-part tariff aims to approximately recover the costs that each customer imposes on the energy infrastructure in terms of their share of both the fixed and variable costs of electricity consumption. An appealing property of these tariffs is that they ensure that, regardless of usage, customers pays their share of the fixed costs incurred by the TD&R licensee. In addition, they ensure some revenue stability for the TD&R licensee.

c. **Three-part tariffs**

109. Finally, a three-part tariff could be used for electricity pricing. A three-part tariff is essentially a two-part tariff but with the addition of a flat-rate (or invariant) fixed charge.

d. **Block tariff**

110. A final option for electricity pricing is to price electricity usage on inclining or declining blocks. Under this scheme, the first units of electricity consumption in terms of kWh (first "block") are charged at a certain price, followed by a second category for higher usage charged at a higher price (for inclining blocks) or a lower price (for declining blocks), and so on.

111. The use of inclining blocks can be justified on both distributional and conservational grounds.25 In terms of distributional concerns, low-income households are more likely to consume energy at low-tier rates, and high-income households at high-tier rates, redistributing the revenue burden to the wealthiest households.26 In terms of conservational concerns, by charging additional energy usage at increasing per-unit cost, price-sensitive customers will be incentivised to keep their energy consumption down, thereby promoting energy efficiency. However, while appropriate for some customer classes, inclining blocks can also penalise those who require more electricity, particularly for commercial reasons; in some cases, declining block tariffs may be preferred on the basis that they offer an effective volume discount.

112. With inclining or declining block tariffs, the two major control levers are the level at which the tariffs are set and the rate of change between the tariff blocks. A particularly steep ascent from one block to the next may incentivise greater energy consumption but may also have equity implications since this is likely to have the greatest impact on the most price-inelastic customers. Conversely, tariff blocks that incline less aggressively provide less incentive to conserve energy consumption.

[24] Capacity charges differ from peak tariffs (as outlined in section a) since capacity charges are based on the customer's own peak electricity usage, whenever that peak occurs, as opposed to being based on periods of high overall system demand. Equivalently, peak tariffs are intended to incentivise electricity use at the margin at specific times, whereas capacity charges aim to incentivise the efficient conservation of electricity on a continuous basis.

[25] Borenstein, S. (2016), The economics of fixed cost recovery by utilities, *The Electricity Journal*, **29**:7, p. 9.

[26] Borenstein, S. (2016), The economics of fixed cost recovery by utilities, *The Electricity Journal*, **29**:7, p. 9.

ANNEX 1.2: FORM OF REVIEW

1. FORM OF REVIEW

113. The two most common methods for regulation of an entity's economic performance in a utility context are rate-of-return regulation (also referred to as cost-plus regulation) and incentive regulation—employing either price and/or revenue caps.

a. **Rate-of-return regulation**—under this form of regulation, tariffs are set at a level that reflects the cost of service. For an agreed base period, usually covering the previous 12 months, an entity calculates operating costs, depreciation, the capital base and its cost of capital. The regulator audits these calculations and determines the fair total revenue allowance and the level of tariffs. These tariffs may stand until the realised return on capital differs from the allowed return. This deviation may lead to a tariff review to realign the required and actual rates of return.[27] The current regulatory system in the electricity sector of Bermuda, i.e. the base-rate filing system, is a form of rate-of-return regulation.

b. **Incentive regulation**—this involves setting either price or revenue caps linked to an efficient cost forecast. These caps are in place for a fixed period, thereby providing an incentive to outperform, i.e. firms are allowed to retain the benefits of any cost reductions beyond those expected at the last tariff review. The incentive period typically lasts from three to five years, with the regulator undertaking a review of allowed prices at these intervals.

114. Rate-of-return regulation and incentive regulation imply a difference in risk exposure, incentives and rewards for the regulated companies. The Authority explores the main differences between these two types of regulation methods below.

c. **Cost-efficiency incentives**. Rate-of-return regulation tends to be based on historical data, which provides an assurance that the entity will be able to recover its costs. Incentive regulation is generally more explicitly forward-looking — it relies on the regulator's ability to forecast efficient cost levels with a reasonable degree of certainty at price reviews. On the one hand, it creates incentives for cost efficiency, which may translate into lower tariffs. However, entities also face the risk associated with the possibility of cost forecasts being inaccurate.

d. **Investment incentives**. Since rate-of-return regulation allows pass-through of any CAPEX and ensures a sufficient return on the capital base, there is a risk that the entity will over-invest in its capital, thereby tending to increase customer bills. With incentive regulation, there could be a bias towards either over- or under-investment in network assets based on the allowed rate of return. Specifically, there is risk of over-investment in network assets within incentive regulation if the allowed cost of capital is too high; conversely, there is a risk of under-investment under incentive regulation if the allowed returns are inaccurately forecast and inadequate. This may undermine the quality of the provided service.

e. **Risk to company and cost of capital.** Incentive regulation exposes a company to a higher degree of risk—for example, a company bears the risk of cost under-performance against its OPEX allowances. As a result of this high risk, the allowed cost of capital under incentive regulation may be higher than under rate-of-return regulation.

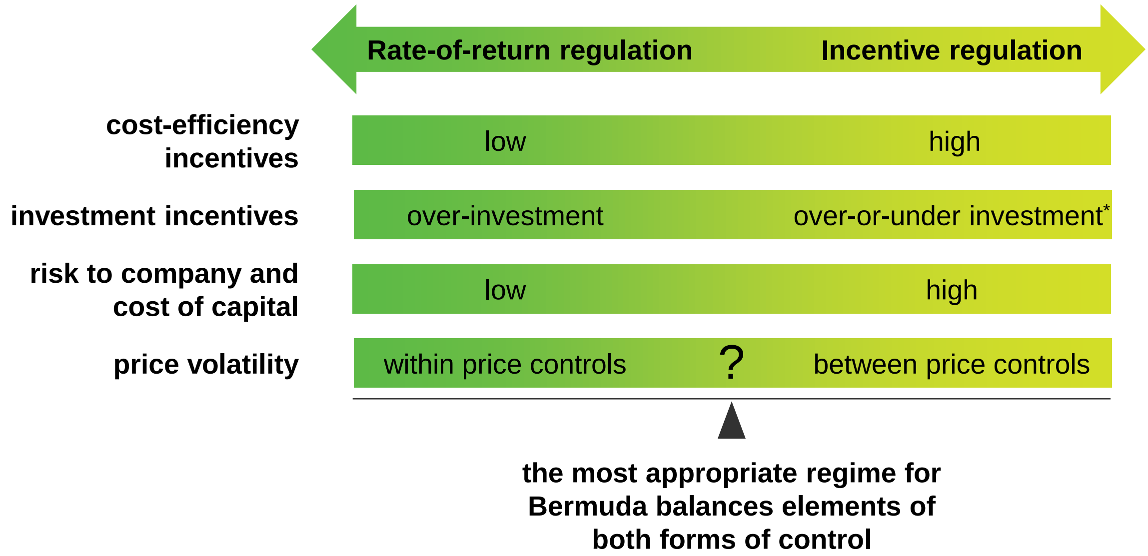
f. **Price volatility.** Consumers bear substantially more risk of cost and revenue shocks being directly passed through into higher prices under rate-of-return regulation. Incentive regulation tends to create a relatively smooth tariff pattern for a review period; however, there is a risk of a substantial movement in tariffs at the end of the review period once all allowances (e.g. OPEX) are reconsidered.

115. Therefore, pure rate-of-return regulation and incentives regulation can be thought of as at opposite ends of the spectrum of possible regulatory regimes. As a result, the differences in

[27] A review of tariffs may be instigated upon the request of the company and/or the regulator.

risk exposure, incentives and reward should be balanced in the design of a regulatory system. These trade-offs are summarised in Figure 5.1.

Figure 5.1 Spectrum of possible regulatory regimes



Note: * If the allowed returns are inaccurately forecast.

116. In addition, the Authority notes that incentive regulation presents a number of methodological choices that would affect both the strengths of incentives and distribution of risks. Specifically, the Authority highlight the duration of the review period and whether the regime operates under a price or revenue cap as characteristics of the incentives-based regime that it is important to consider.

g. **Duration of the review period**. A longer review periodstrengthens incentives, potentially leading to higher risk to the company as allowances are set based on forecasts for longer periods. At the same time, the shorter the review period, the more frequently the regulator will need to undertake the assessment, which increases the burden on the regulator and thereby undermines the overall efficiency of the regulatory regime.

h. **Price cap or revenue cap.** Where a pure revenue cap is used, the prices can be adjusted to recover any difference between the expected and realised volumes, i.e. volume risk is borne by customers. Under a price-cap regime, no adjustments due to deviations from volume forecasts are allowed, i.e. volume risk is borne by the regulated entity.