Analysis of Electricity Cost Drivers, Recommendations, and Impact Assessment Report

17 MAY 2026

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Definitions

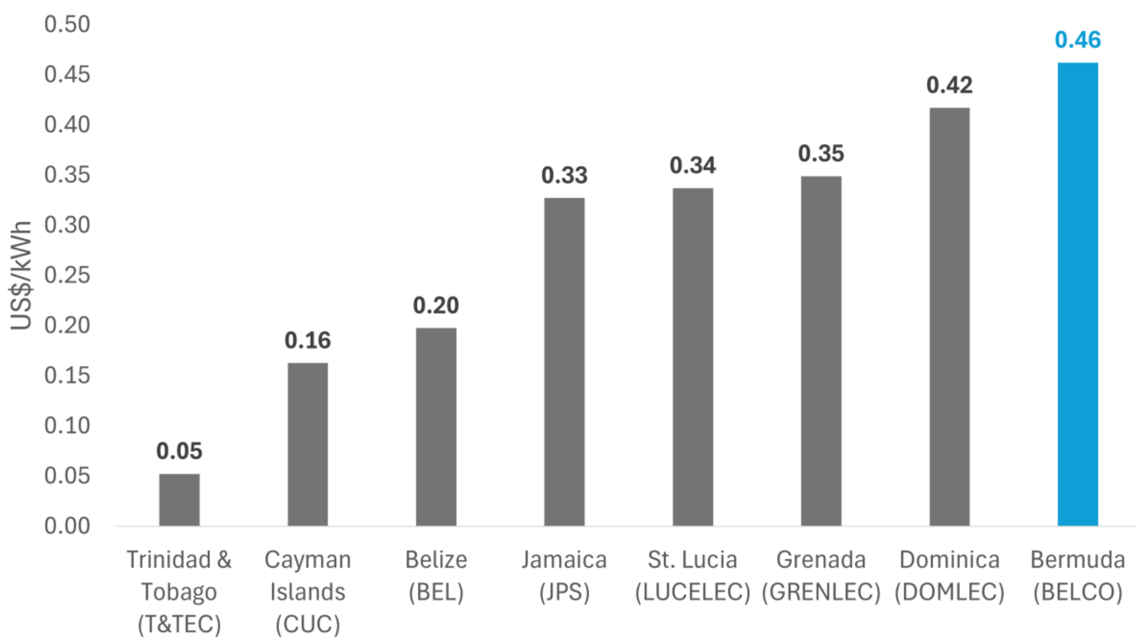
BELCO	Bermuda Electric Light Company
BMD	Bermudian dollar
BGSUI	Bulk generation sole use installation
BLPC	Barbados Power and Light Company
CAPEX	Capital expenditure
CAPM	Capital asset pricing model
CJF	Capital Justification Form
CORE	Consumer Owned Renewable Energy programme
CUC	Caribbean Utilities Company, Ltd.
DER	Distributed energy resource
DG	Distributed generation
DoE	Department of Energy
DoP	Department of Planning
EV	Electric vehicle
FAR	Fuel Adjustment Rate
FIT	Feed-in tariff
GFC	Graduated facility charge
HFO	Heavy fuel oil
IPP	Independent power producer
IRP	Integrated Resource Plan/Planning
IRR	Internal rate of return
kWh	Kilowatt-hour
LCOE	Levelised cost of energy
LNG	Liquified natural gas
MW	Megawatt
NESP	National Electricity Sector Policy
OfReg	Utility Regulation and Competition Office
OPEX	Operating expenditure
PDP	Permitted Development Permit
PPA	Power purchase agreement

RA	Regulatory Authority
RAB	Regulatory asset base
RE	Renewable energy
ROR	Rate of return
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SPD	Short Project Description
Sq. ft.	Square feet
T&D	Transmission and distribution
TD&R	Transmission, distribution and retail
TOU	Time-of-use
WACC	Weighted average cost of capital

Executive summary

Bermuda has among the highest electricity tariffs in the region, with an average tariff of $0.46 per kWh in 2026,[1] as shown in Figure 0.1 below.

Figure 0.1: Benchmarking of Caribbean average electricity tariffs



Notes: Average tariffs are calculated as total revenue from electricity sales divided by total electricity sales (kWh), based on the most recent available utility financials. It is worth noting that electricity tariffs are highly subsidized as the National Gas Company supplies to the utility (T&TEC) at highly subsidised rates.
Sources: RIC. "T&TEC's Annual Performance Indicator Report for the year 2021," pp. 3-10. Link; Energy Chamber of Trinidad and Tobago. 2017. "Understanding the electricity subsidy in T&T". Link; CUC. "Annual Report 2024," p.8. Link; JPS CO. "Annual Report 2024," p. 20. Link;LUCELEC. "Annual Report 2024," p. 56. Link; GRENLEC. "Annual Report 2024," p. 85. Link; DOMLEC. "Annual Report 2024," p. 94. Link

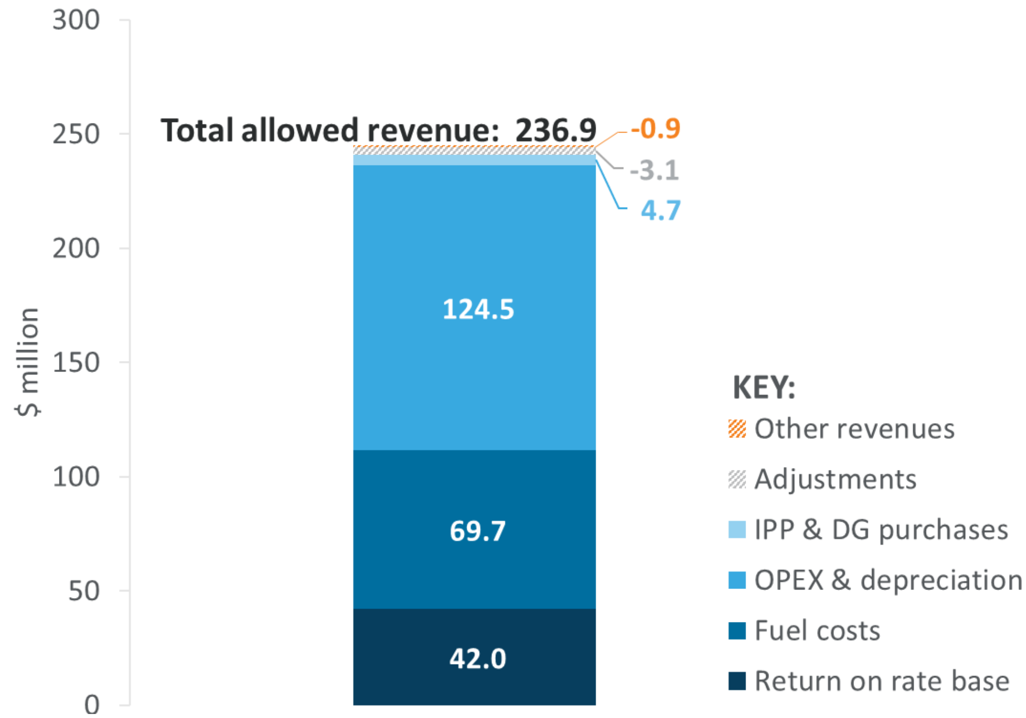
Under Section 35 of the Electricity Act, the retail tariff methodology must enable BELCO to generate a total revenue sufficient to recover its reasonable, prudent, and efficiently incurred costs, together with a reasonable return on investment. The RA is responsible for setting tariffs in accordance with these principles,[2] and the Fuel Adjustment Rate (FAR) is a pass-through mechanism that recovers actual fuel costs from customers.

[1] Based on total revenue allowance and total forecasted sales for the 2026 tariff review period. RA. December 2025. "Retail Tariff Review Public Report." Link

[2] Government of Bermuda. "Electricity Act 2016," Section 35

The allowed revenue for the 2026 tariff review period shows that the largest drivers of electricity costs are operating expenditures (OPEX) and depreciation (about 53 percent of allowed revenue), fuel costs (close to one-third), and the return on the rate base (about 18 percent), as shown in Figure 0.2 below.

Figure 0.2: Breakdown of BELCO's approved revenue allowance for 2026



Note: Other revenues and adjustments are negative values and represent deductions from the 2026 approved revenue allowance.
Source: RA. December 2025. "Retail Tariff Report Public Report". Link

The Government of Bermuda has identified affordability as a priority and engaged Castalia to identify the main drivers of costs and practical steps that can reduce them. This engagement focuses on legislative and regulatory measures, including a targeted review of Section 35 of the Electricity Act 2016 and other tools and mechanisms that can ensure cost-recovery and limit upward pressure on retail tariffs.

This report examines five areas where reform can have the greatest impact:

- The process for developing the Integrated Resource Plan (IRP);
- The framework for distributed generation;
- The retail tariff setting methodology;
- The licensing framework; and
- The role of the Ministry of Home Affairs in shaping the electricity sector.

For each area, the Report identifies the main challenges under the current framework and sets out practical measures the Government can take to address them and achieve its objectives. Some measures can be implemented within the existing framework, others require the Minister to direct the Regulatory Authority (RA) to update its methodologies, and a small number will require amending the Electricity Act.

Integrated Resource Planning

An effective IRP is the primary tool for identifying the least-cost mix of generation and network investments required to meet demand reliably, affordably, and in accordance with policy objectives.

Bermuda's current IRP framework is not delivering these outcomes efficiently. The sector continues to rely on the 2019 IRP, while the current IRP cycle has been underway for more than 3 years, against international best practice of 12 to 24 months.[3] The delays defer least-cost capacity procurement decisions and create uncertainty for investors and other stakeholders about Bermuda's future generation mix.

Three challenges drive these delays:

- A lack of coordination between policy formulation and sector planning: The IRP process started in November 2022 but suffered prolonged delays, during which the Government began developing the draft 2026 National Electricity Sector Policy (NESP). The IRP was ultimately paused in late 2025 so that it could be aligned with the updated policy framework once finalised.[4]
- Late changes to modelling assumptions, requiring Bermuda Electric Light Company (BELCO) to rerun technical studies that could have been avoided had assumptions been settled at the outset.[5]
- Duplication of analytical work between BELCO and the RA, with each engaging its own consultants to conduct or review similar technical studies, increasing costs that are ultimately passed through to customers.[6]

The Government can address these challenges by directing the RA to introduce a formal alignment stage at the start of the IRP process. During this stage, key inputs, assumptions, scenarios, and evaluation criteria would be defined, consulted on, and finalised before detailed modelling begins. This would ensure that BELCO and the RA operate on a common analytical basis, narrow the scope for divergent technical work later in the process, and provide stakeholders with an early point of engagement. The Minister could use this stage to set policy priorities, giving the Government meaningful influence without transferring ownership of the plan. This change does not require statutory amendment.

The Minister has the option to go further and amend the Electricity Act to transfer responsibility for preparing the IRP from BELCO to the RA. Either approach can work, provided robust upfront

3 Caribbean Development Bank. 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries," p. 21.

4 Ministry of Home Affairs. November 2025. "Electricity IRP Suspension Order 2025: Draft 3 for Consultation – Electricity (Integrated Resource Planning process Suspension and Reconstitution Order 2025."

5 Meeting with BELCO. May 2026.

6 Meeting with Department of Energy. February 2026.

alignment is in place. If this route is chosen, it is recommended that responsibility for maintaining supply reliability be transferred to the RA, since BELCO could not fairly be held accountable for capacity shortfalls resulting from a generation mix it did not determine.

Distributed generation

Distributed generation (DG) is now a meaningful part of Bermuda's generation mix. Installed DG capacity has doubled over the last decade to about 14MW, equivalent to 9 percent of total utility-scale installed capacity (164MW)[7] and 13 percent of peak load (105MW).[8] By 2050, the total DG capacity in Bermuda is expected to reach 35MW.[9]

DG is expected to keep growing significantly, driven by economics that make it attractive for many customers. DG is already cheaper than grid electricity, on average, with a levelized cost of $0.18 to $0.24 per kWh[10] against the average tariff of $0.46 per kWh. This suggests that investment in DG is likely to continue to grow as falling technology costs and advances in storage further improve its economic attractiveness to customers.

The current framework was not designed to manage high and growing levels of customer-owned generation. As a result, Bermuda faces interrelated challenges related to DG:

- Cross-subsidisation between DG and non-DG customers and the volatility in the feed-in tariff (FIT) can distort price signals and lead to sub-optimal investment decisions. Because the existing tariff structure recovers most fixed costs through energy charges on a per kWh basis,[11] DG customers do not pay their full share of the fixed costs they impose on the system. This means the savings a customer sees on their bill from installing DG exceed the actual cost savings to the system, encouraging more DG investment than is economically efficient. Because the FIT moves with quarterly fuel costs,[12] the revenue stream from exported generation can be hard to predict over the multi-year horizon of a DG investment, which raises the perceived risk and can deter customers from investing even where DG would otherwise be economically efficient.

- Grid stability risks from DG expansion are not systematically assessed. Neither the IRP process nor the DG approval framework evaluates how much DG Bermuda's grid can absorb before causing voltage violations, frequency instability, or overloading.[13] Although

7 Government of Bermuda. April 2026. "The National Electricity Sector Policy Consultation Draft" Link

8 Meeting with BELCO. April 2026

9 RA. July 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," p. 35. Link

10 The range is calculated based on a range of possible low and high estimates for unit capital cost. The low end of the range is based on the midpoint estimate of Lazard's LCOE+ analysis of $2,450 per kW (Lazard. June 2025. "Lazard LCOE+" Link), while the high end of the range is based on solar PV system and installation costs in Bermuda and equals $3,310 per kW (Sunny Side Solar. "Why Solar?" Link). Other assumptions include: system size of 11kW based on total DG capacity of 14.5MW divided by 1,325 DG customers (data shared by BELCO. May 2026); annual fixed OPEX of $30 per kW (NREL. "Residential PV." Link); capacity factor of 18 percent (BELCO. May 2024. "2023 Integrated Resource Plan Proposal" p.35 Link); discount rate of 10 percent; and system lifetime of 30 years.

11 RA. October 2022. "Retail Tariff Design Restructuring Report" Link

12 RA. September 2023. "Feed-in Tariff General Determination" Link

13 RA. June 2019. "Bermuda Integrated Resource Plan," p. 60. Link; RA. July 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," p. 47. Link

BELCO screens individual applications upstream through its Residential Solar Feasibility Study process before the Department of Planning approves DG applications,[14] the absence of locational hosting capacity studies and of systematic coordination between the Department of Planning, the Department of Energy, and the RA leaves the Government without a clear view of cumulative DG impacts.

- The lack of upfront DG planning is likely to increase system costs. Without a planned approach, BELCO could be forced to take reactive, unplanned measures to maintain grid stability—measures that are typically more expensive than the same actions planned in advance.

Together, these challenges create risk to BELCO's financial viability. As fixed costs are spread across declining grid sales, tariffs rise, strengthening the case for further DG adoption and further reducing grid sales. This self-reinforcing cycle, often referred to as the "utility death spiral," has already begun to play out, as BELCO's sales fell by 13 percent since 2010,[15] which has led bundled rates to increase by an estimated 2 percent.[16]

The Government can address these challenges through four complementary measures:

- Integrate DG into the IRP by directing the Department of Energy to establish and maintain a national Distributed Generation Register that records all approved DG installations, their cumulative capacity, and their geographic location; and by amending Section 40(2) of the Electricity Act to require the IRP to forecast DG capacity, model its impact on grid operations and system costs, and define the cap beyond which grid stabilisation investments must be procured, drawing on data from the Distributed Generation Register as the authoritative data source for its DG forecasts and locational grid impact analysis.
- Strengthen the interconnection approval process by formalising notification between the Department of Planning, the Department of Energy, and the RA, and by directing the RA to develop a list of pre-approved DG equipment to speed up technical inspections.
- Lock in the FIT by amending Section 49 of the Electricity Act so that the Standard Contract specifies a fixed FIT (set by the RA for a defined period, for example, 7 to 10 years), with the FIT for new contracts updated periodically to reflect changes in system costs.
- Reduce cross-subsidisation between DG and non-DG customers by directing the RA to consider DG-specific measures alongside its broader tariff redesign options, for example, establishing a tariff structure specifically for DG customers with fixed and demand-based charges to recover the cost that they incur on the grid.

14 BELCO. 2026. "Solar Connection". Link

15 Meeting with BELCO. April 2026

16 BELCO. "Utility Spiral and Energy Transition Planning & Operations," Presentation shared by BELCO in May 2026

Retail tariffs

Section 35 of the Electricity Act sets out the legal framework for retail tariffs.[17] It requires the RA's tariff methodology to allow BELCO to recover investment that is prudently incurred and used and useful, together with a reasonable return on investment commensurate with the return on investments in businesses with comparable risks and sufficient to attract capital. The methodology must also allow BELCO to recover its reasonable and efficiently incurred operating expenses, fuel costs, generation procurement costs, and statutory fees.

The RA sets retail tariffs using a building-blocks methodology that combines an ex-ante revenue cap with incentives for cost efficiency and penalties for failing to meet service standards.[18] BELCO has generally met these standards, with one recent penalty in 2024/2025 reducing the average tariff by 0.5 percent.[19]

However, the way the RA applies this methodology lacks transparency, particularly in the steps from BELCO's submission to the Board's final rate of return decision and in the basis on which the RA assesses recoverable capital expenditures (CAPEX) and OPEX. Concerns about the application have been raised from both directions: The Government has expressed concerns that the framework may allow BELCO to recover imprudent or inefficient expenses, while BELCO has challenged the application of the methodology on both the rate of return and the disallowance of specific CAPEX and OPEX items in the case *BELCO vs RA (2024)*.

The Supreme Court of Bermuda upheld the RA in that case,[20] which suggests the methodology itself is consistent with the Electricity Act. However, the underlying transparency issue remains, which might make it difficult for Government to verify that tariffs reflect only reasonable and efficient costs.

The tariff is also exposed to fuel price volatility, with fuel costs passed through to customers via the FAR. BELCO's recent fuel cost stabilisation measures have reduced FAR volatility by about 73 percent since 2025.[21] However, these gains depend on BELCO's operational decisions rather than on features embedded in the regulatory framework: There is no formal hedging strategy approved by the RA, nor an explicit risk-management framework.

Finally, the tariff structure drives cross-subsidisation between customer classes. Around 80 percent of revenue is recovered through variable energy charges, while roughly 80 percent of BELCO's costs are fixed.[22] A customer's contribution to system costs, therefore, depends primarily on how much electricity they consume, rather than on the actual cost of serving them. This

[17] Government of Bermuda. "Electricity Act 2016," Section 35

[18] RA. January 2025. "Retail Tariff Review 2026-2027 – Information Request #1".

[19] The Retail Tariff Review 2024 Public Report explains that the penalty accounts for "a 0.5% decrease approximately." It is unclear if this decrease refers to the total average rate or to the base rate. RA. July 2024. "Retail Tariff Review," Section VI. Link.

[20] Supreme Court of Bermuda. February 2024. "Bermuda Electric Light Company Limited v. The RA (2022 No. 97 Civ)". Link

[21] Based on quarterly FAR values from Q1 2023 to Q2 2026. Standard deviation calculated using quarterly FAR values in $ per kWh. Q1 2023-Q4 2024 standard deviation: $0.030 per kWh; Q1 2025-Q2 2026 standard deviation: $0.008 per kWh. BELCO. 2026. "Fuel Adjustment Rates". Link

[22] Meeting with RA. April 2026

inversion weakens price signals and is intensified by rising DG penetration, as costs shift onto customers who continue to rely on the grid.

The Government can address these challenges using the Minister's existing powers to issue general policy directions to the RA, combined with the RA's power to issue general determinations, without requiring any change to the law. Three sets of measures are recommended:

- Increase the transparency of the tariff-setting methodology. The Minister can direct the RA to define a clearer and more predictable process for setting the allowed rate of return, including a single methodology for estimating the cost of equity and a single point estimate at each stage of the process. The Government may also request information from the RA on the outcomes of its prudency reviews and, if further assurance is needed, commission an independent prudency assessment of BELCO's costs.
- Stabilise tariffs by directing the RA to strengthen fuel cost risk management. This could include developing a formal fuel cost risk management framework, requiring BELCO to submit a hedging strategy for RA approval (with defined objectives, instruments, exposure limits, and reporting), and updating the FAR methodology to incorporate stabilisation tools such as a fuel cost smoothing mechanism, risk-sharing between BELCO and customers, or less frequent FAR revisions.
- Reduce cross-subsidisation between customer classes by directing the RA to take forward its tariff redesign options. The RA has already developed four options,[23] ranging from a modest unbundling of variable rates to a more cost-reflective design with peak power charges per customer class that better reflects the underlying cost structure. Tariff design sits within the RA's remit, so the report does not recommend a specific option.

Licensing

BELCO holds Bermuda's only Transmission, Distribution and Retail (TD&R) Licence through 2047, and the Electricity Act prohibits customers from receiving electricity from any other party.[24]

The current framework has worked well historically in a sector centralised around a vertically integrated utility. However, the framework is becoming inadequate as new technologies and business models emerge that do not fit easily within a single-licensee structure. Two specific issues are emerging:

- First, EV uptake is set to grow rapidly: The draft 2026 NESP estimates that EVs could add up to 54GWh of annual demand by 2045,[25] about 10 percent of forecasted 2026 total electricity sales.[26] The current framework, if unchanged, will become a constraint on EV uptake: EV charging at a public station may be considered retail supply, which means charging operators have no clear legal basis to recover the cost of the electricity they

[23] RA. October 2022. "Retail Tariff Design Restructuring Report," p.7. Link

[24] Government of Bermuda, "Electricity Act 2016," Section 19(2)(b). Link

[25] Government of Bermuda. April 2026. "The National Electricity Sector Policy Consultation Draft" Link

[26] RA. December 2025. "Retail Tariff Review Public Report". Link

provide. Both the draft 2026 NESP and the National Electric Vehicle Charging Infrastructure Policy already recognise the need for legislative change to enable charging at scale.

- Second, large users cannot procure electricity directly from third-party generators,[27] even in cases where this could reduce total system costs. This is becoming more relevant as data centre operators and other large international businesses seek dedicated renewable supply to meet corporate sustainability commitments, a trend that has driven a growing number of direct generator-to-end-user power purchase agreements globally.

The Government can address both issues through the following targeted amendments to the Electricity Act, without opening general retail competition or undermining BELCO's TD&R Licence:

- Allow third-party EV charging by clarifying that supplying electricity through EV charging infrastructure does not constitute retail supply of electricity. This recognises that EV charging is a service provided at a transient point of supply rather than the supply of electricity to fixed premises.
- Allow third-party supply to large users by enabling the RA, on a case-by-case basis, to license an independent power producer to generate, access the grid, and supply a contracted large user through a bilateral arrangement. The RA would grant such licences only where they reduce total system costs, do not shift costs onto other customers, maintain system reliability, support environmental objectives, and are consistent with the IRP. Third-party generators would pay appropriate use-of-system and back-up capacity charges, and BELCO would remain the default supplier and the sole counterparty for general retail service.

Minister's role in the power sector

The Electricity Act and Regulatory Authority Act give the Minister several channels to shape the electricity sector, including:

- Ministerial declarations,[28]
- Directions to the RA, in which the Minister has substantial discretion to set policy priorities and resolve trade-offs,[29]
- Regulations establishing the general requirements regarding the means by which the RA implements the Electricity Act, Regulatory Authority Act, and approved sectoral policies,[30] and
- Requests for technical analysis from the RA.[31]

The framework deliberately reserves case-specific decisions for the RA to protect its regulatory independence, and prevents the Minister from directing the RA on the application of policy to

[27] Government of Bermuda. “Electricity Act 2016,” Section 48

[28] Government of Bermuda. “Electricity Act 2016,” Section 7(2); “Regulatory Authority Act 2011,” Section 4(2)

[29] Government of Bermuda. “Electricity Act 2016,” Sections 8(1)-(2); “Regulatory Authority Act 2011,” Sections 7-8

[30] Government of Bermuda. “Electricity Act 2016,” Section 54; “Regulatory Authority Act 2011,” Section 5

[31] Government of Bermuda. “Electricity Act 2016,” Section 12

specific licensees or matters. In practice, the Minister directly sets policy for the sector and indirectly shapes the RA's methodologies through directions and declarations, while case-specific decisions remain with the RA.

The Minister can use these existing powers more deliberately to deliver on the Government's affordability commitments, without requiring statutory amendment, to:

- Ensure the RA's methodologies are aligned with policy objectives by issuing the 2026 NESP as a formal Ministerial declaration under Section 7(2) of the Electricity Act. Citing the statutory basis explicitly places the NESP unambiguously within the scope of Section 15(1) of the Regulatory Authority Act, which requires the RA to perform its functions in accordance with Ministerial policies.
- Shape methodologies upstream rather than seeking to influence specific outcomes downstream, by combining the declaration with a Section 8 Ministerial direction requiring the RA to give effect to the NESP's objectives on affordability, reliability, and renewable integration when setting its methodologies and service standards. The direction would need to remain within the limits of Section 8(4), which prevents directions on individual licensees or specific matters. The Minister could request the RA's advice under Section 12 to ensure the direction is one the RA can act on.
- Use policy directions to address system-wide risks where there is a clear public-interest case, recognising that the Minister cannot direct outcomes in specific cases but can shape the framework within which the RA acts.

1 Introduction

Bermuda has among the highest electricity tariffs in the region, with an average tariff of $0.46 per kWh for the tariff review period 2026.[32] The Government has set a clear priority for the sector: reducing electricity costs and ensuring that the tariffs paid by customers reflect only the reasonable, prudent, and efficiently incurred costs of supplying electricity.

The Government of Bermuda engaged Castalia to support identifying the legislative and regulatory changes needed to deliver on that priority, focusing on:

- A targeted review of Section 35 of the Electricity Act 2016, which sets out the legal framework for retail tariffs and requires the RA's tariff setting methodology to enable BELCO to recover its reasonable, prudent, and efficiently incurred costs and a reasonable return on investment; and
- Recommendations for legislative and regulatory changes, tools, and mechanisms that can better ensure cost-recovery, reduce cross-subsidies, and limit upward pressure on retail tariffs.

This Report looks at what is driving costs and what can be done to reduce them over time. It focuses on practical changes to how the system is planned, regulated, and priced to address three core challenges:

- Planning is not delivering least-cost outcomes. Delays and lack of coordination between policy and planning have weakened the Integrated Resource Plan (IRP) process, deferring procurement decisions and creating uncertainty about the future generation mix.
- Distributed generation (DG) is growing rapidly, but an update to the framework is needed to ensure DG helps to lower system costs, while managing risks to grid stability and sending the right price signals to customers.
- The tariff structure is misaligned with underlying system costs. Most system costs are fixed, but are largely recovered through variable charges, leading to inefficient incentives, volatility in customer bills, and uneven cost allocation across customers.

In response to these challenges, this Report recommends a package of measures that can be implemented within the existing framework, along with a few targeted legislative changes where needed. These include:

- Strengthening and streamlining the IRP process (Section 2);
- Ensuring that the expansion of DG is done in a least-cost way and preserving grid stability and reliability (Section 3);
- Improving transparency and stability in retail tariff-setting (Section 4);

[32] Based on total revenue allowance and total forecasted sales for the 2026 tariff review period. RA. December 2025. "Retail Tariff Review Public Report." Link

- Allowing third-party participation in cases where it can reduce system costs and improve system resilience, notably in the context of electric vehicle (EV) uptake (Section 5); and
- Using the Minister of Home Affairs' existing powers more effectively to guide the sector in line with Government policy and objectives (Section 6).

Implemented together, these measures form a coherent response to the structural drivers of high electricity costs in Bermuda. In the near term, they will start to relieve upward pressure on tariffs and give customers greater confidence that the costs being passed through reflect only what is reasonable, prudent, and efficient. Over the longer term, they will position Bermuda's electricity sector to deliver least cost and reliable supply.

2 Integrated Resource Planning

The 2026 draft National Electricity Sector Policy (NESP) recognises the IRP as the foundation of long-term planning, responsible for identifying the least-cost electricity plan.[33] An effective IRP is the main tool used to decide what electricity generation and network investments Bermuda will need, and when. An effective and well-functioning IRP identifies the least-cost generation mix required to meet demand while maintaining reliability, affordability, emissions reduction targets, and energy security.[34]

Bermuda's current IRP framework has not delivered these outcomes efficiently. The sector continues to rely on the 2019 IRP, while the process to develop a new plan has been subject to prolonged delays and a temporary suspension. At the same time, policy development and IRP preparation have proceeded in parallel, creating uncertainty about the sequencing between Government policy direction and long-term sector planning.

This section assesses the gaps in the current IRP framework, including policy-planning sequencing, process delays, and duplication of effort between institutions (Section 2.1). It then recommends practical options to streamline the IRP process, clarify roles and responsibilities, and ensure that future planning consistently delivers least-cost outcomes aligned with Government policy (Section 2.2).

2.1 Challenges under the current framework

This section examines key challenges with the current IRP framework, namely:

- The lack of coordination between policy development and sector planning (Section 2.1.1);
- The temporary suspension of the IRP process has delayed planning and procurement and created the need to update assumptions and redo technical studies (Section 2.1.2); and

[33] Government of Bermuda. April 2026. "The National Electricity Sector Policy (Consultation Draft)," Section 5. Link

[34] Caribbean Development Bank. October 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries," p. 20.

- The duplication of planning activities between BELCO and the Regulatory Authority (RA), such as parallel technical assessments and overlapping consultant support, has led to unnecessary costs and delayed decision-making (Section 2.1.3).

These challenges are described in more detail below.

2.1.1 Lack of coordination between energy policy and sector planning

Under Section 40(2) of the Electricity Act, the IRP must:

- Prioritise actions that most meet the purposes of the Electricity Act;
- Conform to Ministerial directions; and
- Be reasonably likely to supply electricity at the least cost, subject to policy trade-offs defined in Ministerial directions or instructions from the RA.[35]

The RA's instructions, defined in the IRP Proposal Guidance, further require the IRP to reflect policy objectives. For example, the 2022 IRP Proposal Guidance states that the IRP Proposal must reflect RA and Ministerial policy guidance, with overarching policy objectives including affordability, system reliability, and environmental sustainability, and consider Bermuda's NESP and National Fuels Policy.[36]

In practice, however, a lack of coordination in policy and sector planning has increased the risk that IRP outcomes do not fully align with current policy objectives. This misalignment has arisen in two ways. First, past IRPs have been developed against outdated policy frameworks. Second, more recently, IRP preparation and policy formulation have advanced in parallel, creating uncertainty about the objectives the IRP is meant to serve.

For example, the experience of the 2019 IRP illustrates these risks. The 2015 NESP set a target of 38 percent renewable energy (RE) generation by 2035.[37] In developing the 2019 IRP, eight scenarios were assessed, spanning different levels of RE. This included a high-RE pathway scenario, which achieved 85 percent renewable generation by 2035,[38] with all new capacity additions over the 20-year planning period (2020-2040) coming from renewables.[39] The RA ultimately selected this pathway for implementation, despite there being a lower-cost alternative combining renewables with liquefied natural gas (LNG).

While this decision reflected broader policy considerations at the time, it demonstrates how IRP outcomes can move beyond stated policy targets in the absence of clear, up-to-date direction.

A similar issue arose in the most recent IRP cycle. The RA issued its IRP Proposal Guidance in November 2022, and BELCO submitted a draft IRP in 2023. At the same time, the Government had begun developing the draft 2026 NESP. As a result, the IRP and the new policy were being

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[35] Government of Bermuda. "Electricity Act 2016," Section 40(2)(b), p.22.

[36] RA. 2022. "Integrated Resource Plan (IRP) Proposal Request," pp. 5, 7–8.

[37] RA. 2019. "Bermuda Integrated Resource Plan," p. 13. Link

[38] RA. 2019. "Bermuda Integrated Resource Plan," p. 5. Link

[39] RA. 2019. "Bermuda Integrated Resource Plan." p. 6. Link

prepared in parallel, rather than through a clear sequence in which Government policy direction guides long-term resource planning.

Once the draft NESP was introduced, the IRP process was paused to align it with the updated policy framework. While this ensures consistency in the final plan, it delays decision-making and requires rework of the analysis already completed.

2.1.2 Delays in planning and procurement

The IRP process in Bermuda has been subject to prolonged delays compounded by the sequencing issue described above, undermining its role as a timely tool for least-cost planning. Best practice is for an IRP to be completed within 12 to 24 months,[40] but Bermuda's current IRP process has been underway for more than 3 years.[41]

The process began in November 2022 when the RA issued the IRP Proposal Guidance, requiring BELCO to submit an IRP proposal within 12 months. BELCO submitted the proposal in November 2023 and subsequently revised and resubmitted it in March and May 2024 in response to RA feedback.[42] BELCO has indicated that part of the delay arose because key modelling assumptions were not agreed upon at the onset,[43] requiring later changes to inputs such as technology options, capacity factors, fuel prices, and demand forecasts. These changes necessitated re-running technical studies that could have been avoided if assumptions had been settled earlier in the process.[44]

Further delays followed during consultation and review. The RA issued the proposal for public consultation in July 2024, with responses due by October 2024. In late 2025, the IRP process was formally suspended through the Electricity (Integrated Resource Planning Process Suspension and Reconstitution) Order 2025 to allow the IRP to be aligned with the forthcoming NESP 2026.[45]

The suspension paused the process for 18 months beginning in December 2025, including the preparation and submission of the IRP, public consultation, and RA approval, with the intention of resuming a reconstituted process.[46]

These delays are already causing problems and are worsening as assumptions become outdated. The RA has required BELCO to update several IRP inputs, including technology costs and fuel price projections, to reflect market changes since the original submission.[47] The RA has also required revisions to planning parameters,[48] such as reducing the solar capacity cap from 20MW to 16MW,

40 Caribbean Development Bank. 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries," p. 21.

41 RA. 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," p. 3. Link

42 RA. 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," pp. 3-4. Link

43 Meeting with BELCO. May 2026.

44 Meeting with BELCO. May 2026.

45 Ministry of Home Affairs. November 2025. "Electricity IRP Suspension Order 2025: Draft 3 for Consultation – Electricity (Integrated Resource Planning process Suspension and Reconstitution Order 2025."

46 Ministry of Home Affairs. November 2025. "Electricity (Integrated Resource Planning Process Suspension and Reconstitution) Order 2025," Section 4.

47 RA. 2025. "Integrated Resource Plan: Comments to Implement in the Final IRP (3 June 2025)," pp. 4-5.

48 Meeting with BELCO. April 2026

revising renewable and storage capacity limits, delaying timelines for offshore wind and LNG conversion, and updating demand assumptions, including those related to energy efficiency and electric-vehicle uptake.[49]

Delays in developing the IRP are already having effects. For example:

- Increasing costs: BELCO has indicated that, while assumptions on technology costs remain broadly valid,[50] it will need to update its technical studies to reflect changes in the other assumptions. Updating these studies adds an estimated $2 million to what BELCO has already spent on IRP-related modelling and analysis.
- Delays in procuring new capacity: Without an approved IRP, BELCO and the RA cannot identify the current least-cost mix of generation resources for Bermuda or determine which new plants should be procured and when. This increases the risk that capacity additions are delayed or addressed reactively rather than through a planned, least-cost approach.
- Investor uncertainty: The RA and BELCO have both noted that delays to the IRP create uncertainty for stakeholders and investors by reducing visibility on the future generation mix and procurement timelines.[51]

2.1.3 Duplication of planning activities between BELCO and the RA

The current IRP framework leads to duplication of roles and effort between BELCO and the RA, increasing costs and contributing to delays in the planning process.

Under the Electricity Act, BELCO is responsible for preparing the IRP proposal, while the RA is responsible for initiating, guiding, reviewing, and approving the IRP.[52] In practice, however, this division of responsibilities has resulted in parallel analytical work on the same underlying planning matters.

Figure 2.1 summarises the roles and requirements of each entity in the IRP process as detailed in the Electricity Act.

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[49] RA. 2025. "Integrated Resource Plan: Comments to Implement in the Final IRP (3 June 2025)," pp. 4-5.

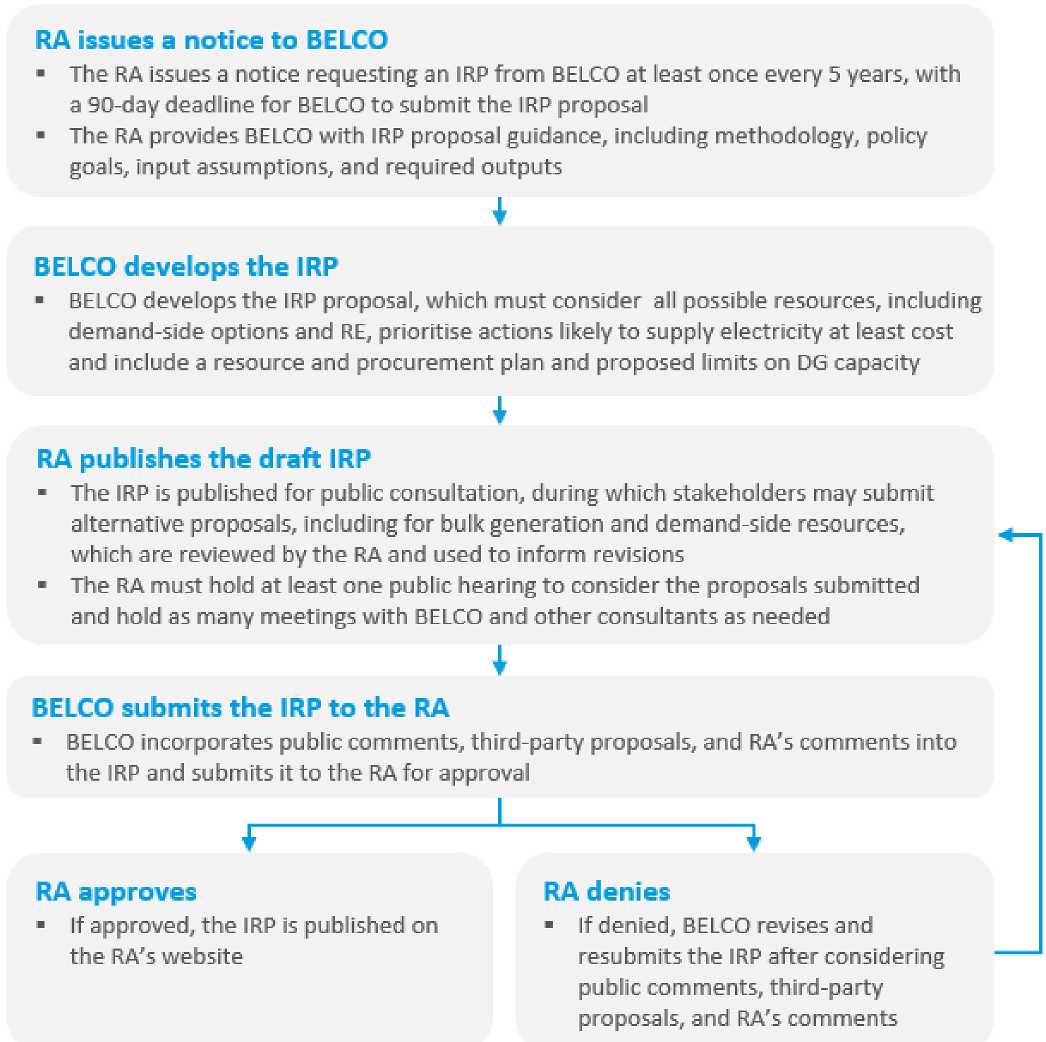
[50] RA. 2026. "Integrated Resource Plan: Comments to Implement in the Final IRP (16 February 2026)," p. 4.

[51] RA. 2025. "Comments on the Electricity Amendment Bill 2025."

[52] Sections 41(1) and 44(1) of the Electricity Act 2016 give the responsibility of preparing and submitting the IRP proposal and final draft IRP to the TD&R Licensee, which is currently BELCO. The TD&R Licence, Section 23, further requires BELCO to comply with Sections 40 to 45 of the Electricity Act as regards the IRP proposal and the IRP.

Government of Bermuda. "Electricity Act 2016," Sections 40-41 and 44.

Figure 2.1: Bermuda's IRP process



Source: Government of Bermuda. "Electricity Act 2016" Part 8 Link; RA. December 2017. "Integrated Resource Plan Guidelines". Link

In practice, to follow the process above, BELCO engages consultants to conduct technical studies and modelling to support its IRP proposal.[53] At the same time, the RA engages its own consultants to review and assess the proposal, often replicating elements of the same analysis.[54] As a result, both institutions incur significant costs (which are ultimately passed on to customers) to evaluate similar scenarios and modelling outcomes.

[53] BELCO. 25 November 2025. "Comments on the Draft Electricity Amendment Act 2025 and Draft IRP Suspension Order 2025," p. 2.

[54] Meeting with Department of Energy. February 2026.

The RA has emphasised this inefficiency, warning that it had already incurred substantial costs and that the IRP pause and reconstitution would place considerable strain on its financial and operational resources, particularly given ongoing challenges in securing timely budget approvals.[55] Similarly, BELCO has raised similar concerns over costs incurred and resources used to develop and revise the IRP proposal.[56]

2.2 Recommendations for improving the IRP process

Bermuda should establish an IRP process that consistently delivers timely, least-cost plans aligned with Government policy, without the duplication of analytical work and procedural delays that have undermined the current cycle. To achieve this, Government may direct the RA to take appropriate actions, within its existing powers, to clarify the roles and process in the IRP preparation and review process. Under Section 8 of the Electricity Act, the Minister of Home Affairs (the Minister) may issue general policy directions to the RA,[57] which the RA is required to follow.[58] If the Minister chooses, amendments to the Electricity Act can also be made to transfer the responsibility of preparing the IRP from BELCO to the RA.

Measures that do not require statutory change

As part of its IRP Proposal Guidance, the RA can introduce a formal ‘alignment’ stage in the IRP process. During this stage, key assumptions, scenarios, and evaluation criteria would be defined, consulted on, and finalised before detailed modelling begins. Such a stage in the IRP process would help ensure that BELCO and the RA are aligned at the outset of the process, and would:

- Ensure that scenarios are based on consistent inputs and accurate, up-to-date inputs, so that differences in outcomes reflect policy trade-offs rather than inconsistencies in the methodology. Clearly defined scenarios and evaluation criteria also provide Government and stakeholders with a transparent basis for comparing options, reducing the need for re-analysis and shortening the review process; and
- Enable stakeholder engagement at an appropriate point in the IRP development process. Engaging stakeholders early, and at the stages where their input can still shape the analysis, narrows the scope for disputes once the IRP is submitted for approval.

The Minister can use its existing powers to further strengthen its influence over the IRP process. For example, as part of this alignment stage, the Minister may direct that the IRP prioritise affordability, or that specific technologies or constraints be considered. This gives the Government meaningful policy influence over the plan without transferring the responsibility to another entity.

Figure 2.2 illustrates the recommended process, where BELCO retains the responsibility for preparing the IRP, as is the case under the current framework.

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55 RA. July 2025. “Memorandum to the Hon. Alexa Lightbourn on the Integrated Resource Plan”, Paragraph 13.

56 BELCO. 25 November 2025. “Comments on the Draft Electricity Amendment Act 2025 and Draft IRP Suspension Order 2025,” p. 2.

57 Government of Bermuda. July 2016. “Electricity Act 2016,” Section 8.

58 Government of Bermuda. 2011. “RA Act 2011,” Section 6.

Figure 2.2: Recommended IRP process for Bermuda

Step 1: RA issues IRP Proposal Guidance

- RA issues IRP guidance, including methodology and required inputs

Inputs may include fuel costs, supply options and technology costs (including distributed generation), reliability standards, value of lost load, forecasted level of distributed generation uptake, grid and policy constraints

Step 2: Align on assumptions, scenarios, and evaluation criteria

- BELCO proposes the initial modelling assumptions, scenarios for supply and demand, and criteria consistent with the guidance
- BELCO consults stakeholders (DoE, RA, developers, public)
- BELCO refines assumptions, scenarios, and criteria based on stakeholder feedback
- BELCO and RA formally agree on assumptions, scenario, and criteria before modelling begins

Scenarios may include a least-cost reliable scenario, a high renewables scenario, and a balance scenario
Criteria may include tariff impact, reliability, stability, flexibility, CO2 emissions, and exposure to fuel supply and price risk

Step 3: Run modelling scenarios

- BELCO runs modeling, including demand forecast and supply and demand scenarios, using the agreed assumptions

Step 4: RA reviews IRP Proposal

- BELCO submits IRP Proposal to the RA
- RA reviews the IRP Proposal and provides feedback to improve the alignment between the IRP Proposal and the IRP Proposal Guidance, if needed
- BELCO addresses RA's feedback and resubmits IRP Proposal

Step 5: RA releases IRP Proposal for stakeholder consultation

- RA publishes the Invitation to Comment on its website, reporting on the evaluation criteria agreed on in Step 2 and the trade-offs for each scenario
- RA requests submissions of proposals for bulk generation or demand side resources

The trade-offs of high renewables scenario, for example, are that this scenario could increase costs but also stabilise them by reducing exposure to fuel price volatility

Step 6: Revise IRP

- BELCO finalises the IRP Proposal, integrating stakeholders' feedback

Step 7a: RA approves IRP Proposal

Step 7b: RA rejects IRP Proposal

Note: In this context, "inputs" refers to the categories of data used in the IRP model, such as technology options, fuel price, and capacity factors. "Assumptions" refers to the values assigned to those inputs, such as the assumed cost of a technology, expected fuel price, or capacity factor used in the modelling.

This recommended IRP process offers a more streamlined form of regulatory oversight than the current framework. Through the alignment stage, BELCO and the RA operate from a common analytical basis. This reduces the need for the RA to undertake parallel technical studies to validate the analysis, while preserving its right to reject or modify the IRP if it does not comply with the agreed framework. The approach also strengthens the role of evidence-based decision-making: rather than defending predefined targets (for renewable generation, for example), the IRP can transparently assess trade-offs and identify least-cost outcomes consistent with Government policy.

Comparable jurisdictions such as Hawaii use a similar integrated planning process, as described in Box 2.1 below.

Box 2.1: Integrated Resource Planning in Hawaii

Hawaii provides a useful example of a planning process that places early alignment, stakeholder engagement, and transparency at the centre of system planning.

Under Hawaii's Integrated Grid Planning framework, the utility leads the technical analysis, but the process is structured and overseen by the regulator and involves stakeholders at defined points in the process. The following are important features that may be relevant for Bermuda:

- **Early agreement on key inputs and assumptions:** To start, utilities must define key inputs to the analysis, such as assumptions, demand forecasts, DG uptake, and generation options. These must be approved by the regulator after stakeholder consultation, before detailed modelling proceeds.
- **Structured stakeholder engagement:** The process involves a wide range of stakeholders, including regulators, consumer advocates, government agencies, independent power producers, environmental groups, technical experts, and other market participants. Stakeholder working groups and review points are built into the process, allowing feedback to be incorporated before key decisions are made, rather than after the analysis is complete.
- **Clear review points and iterative planning:** Utilities develop resource plans alongside a 5-year Action Plan, which are then shared for public and stakeholder review through working groups and formal regulatory processes. Feedback is incorporated before the plans are finalised and submitted for approval. The regulator reviews the plans at defined stages and can request changes along the way. The process is iterative, with plans and action steps updated regularly as assumptions and system conditions change.[59]

Measures that require statutory change

The recommended approach above can be applied regardless of whether BELCO or the RA is responsible for preparing the IRP. If the Government chooses to transfer the responsibility for preparing the IRP from BELCO to the RA, this would require amendments to Sections 40 and 41 of the Electricity Act, which currently require BELCO, as the TD&R Licensee, to prepare and submit the IRP proposal in response to the RA's request.

Under such a framework, BELCO would remain responsible for implementing the IRP once approved. The existing framework already provides for this. Section 20(3) of the Electricity Act requires BELCO to provide for "optimal supply, transmission, distribution and storage of electricity

59 Hawaii Public Utilities Commission. 2025. Integrated Grid Planning Docket for Hawaiian Electric (Docket No. 2018-0165). Link

that are planned, organised, and implemented in accordance with the IRP." Failure to do so may expose BELCO to regulatory action, including adjustment to its allowed revenue under Condition 26(5) of the TD&R Licence.[60] In addition, non-compliance with directions issued by the RA may result in financial penalties under the Regulatory Authority Act, which provides for fines in cases of non-compliance.[61]

The decision to transfer IRP preparation responsibility should be guided by a broader principle: responsibility for planning should, as far as possible, align with accountability for ensuring reliability of supply. Assigning these responsibilities to the same entity ensures that planning decisions are made by the party that bears the consequences. Separating these responsibilities creates a risk that the entity responsible for system reliability has limited influence over planning decisions, while the entity responsible for planning is not directly accountable for the consequences.

The current framework assigns both responsibilities to BELCO: it prepares the IRP and is required to comply with defined service standards for reliability, power quality, and customer service under its TD&R Licence.[62,63]

If the Government chooses to transfer responsibility for preparing the IRP to the RA, it should consider aligning this change with the broader principle that responsibility for planning should sit with the entity accountable for system reliability. In practice, this may require accompanying legislative changes to transfer accountability for reliable supply to the RA.

3 Distributed generation

Distributed generation (DG) is becoming an increasingly significant resource in Bermuda's generation mix. Installed DG capacity has doubled in the last decade, from 7MW in 2017 to 14MW today,[64] equivalent to 13 percent of peak load (105MW),[65] or 9 percent of total utility-scale installed capacity (164MW).[66] By 2050, the total DG capacity in Bermuda is expected to reach 35MW.[67]

[60] RA. January 2025. "Retail Tariff Methodology – General Determination," Section 3.

[61] RA. 2011. "Regulatory Authority Act 2011," Section 98. Link

[62] RA. "Transmission Distribution & Retail Licence," Section 14, p. 40. Link.

[63] The RA sets these standards for each tariff period, including targets and tolerance ranges for System Average Disruption Index (SAIDI), which measures the average duration of supply interruptions per customer, and System Average Interruption Frequency Index (SAIFI), which measures how often interruptions occur.

Government of Bermuda. July 2016. "Electricity Act 2016," Section 32; RA. 2019. "Schedule to RA (Service Standards Indicators for Electricity Licensees) General Determination," Section 32. Link; RA. 16 February 2026. "Annex 1: Service Standards Indicators - Performance Targets 2026," Section 2 ("Reliability of electricity supplied to customers"). Link

[64] Government of Bermuda. April 2026. "The National Electricity Sector Policy Consultation Draft" p. 9. Link

[65] Meeting with BELCO. April 2026

[66] Government of Bermuda. April 2026. "The National Electricity Sector Policy Consultation Draft" Table 1: Current Energy Generation and Capacity. Link

[67] RA. July 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," p. 35. Link

For many customers, self-generation from DG is already cheaper than grid electricity, on average. The levelized cost of distributed solar for an average system[68] in Bermuda is estimated to be between $0.18 and $0.24 per kWh,[69] compared to an average retail tariff of $0.46 per kWh—representing a significant cost advantage.[70] This suggests that investment in DG is likely to continue to grow as falling technology costs and advances in storage further improve its economic attractiveness to customers.

Without the right rules and planning, however, rapid DG uptake can increase overall system cost and create grid instability. Bermuda faces these two risks under the current legal and regulatory framework, as described in Section 3.1. First, the existing tariff structure recovers most fixed costs through energy charges on a per kWh basis. As DG customers buy less electricity from the grid, a growing share of those fixed costs is shifted onto customers without DG, putting upward pressure on tariffs. Second, higher levels of DG make it harder to operate a small, isolated power system safely and reliably. Managing variability, voltage, and system balance requires careful planning, additional grid investment, and clearer technical controls, which are not fully addressed under the current IRP process.

Section 3.2 recommends practical measures to support DG uptake within least-cost planning while keeping the grid stable. These cover four areas: integrating DG into the IRP so that its system impacts are planned for; strengthening the interconnection approval process; locking in the feed-in tariff (FIT) for a defined period to give DG customers revenue certainty; and reducing cross-subsidisation between DG and non-DG customers.

3.1 Challenges under the current framework

DG is expanding quickly in Bermuda, but the current framework was not designed to manage high and growing levels of customer-owned generation. As a result, Bermuda faces interrelated challenges related to DG:

- The current commercial framework does not incentivise an optimal level of investment in DG. Cross-subsidisation between DG and non-DG customers and the volatility in the FIT can distort price signals that can lead to sub-optimal investment decisions (Section 3.1.1).
- Grid stability risks from DG expansion are not systematically assessed. The IRP process does not evaluate how much DG Bermuda's grid can absorb before causing voltage violations, frequency instability, or overloading (Section 3.1.2).

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68 The average system size in Bermuda is 11kW calculated as the total DG capacity of 14.5MW divided by 1,325 DG customers. Data shared by BELCO. May 2026

69 The range is calculated based on a range of possible low and high estimates for unit capital cost. The low end of the range is based on the midpoint estimate of Lazard's LCOE+ analysis of $2,450 per kW (Lazard. June 2025. "Lazard LCOE+" Link), while the high end of the range is based on solar PV system and installation costs in Bermuda and equals $3,310 per kW (Sunny Side Solar. "Why Solar?" Link). Other assumptions include: annual fixed OPEX of $30 per kW (NREL. "Residential PV." Link); capacity factor of 18 percent (BELCO. May 2024. "2023 Integrated Resource Plan Proposal" p.35 Link); discount rate of 10 percent; and system lifetime of 30 years.

70 Based on total revenue allowance and total forecasted sales for the 2026 tariff review period. RA. December 2025. "Retail Tariff Review Public Report." Link

- The lack of upfront DG planning is likely to increase system costs. Without a planned approach, BELCO could be forced to take reactive, unplanned measures to maintain grid stability—measures that are typically more expensive than the same actions planned in advance (Section 3.1.3).

Together, these challenges create risk for BELCO's financial viability. As fixed costs are spread across declining grid sales, tariffs rise, strengthening the case for further DG adoption and further reducing grid sales. This self-reinforcing cycle has already begun to play out (Section 3.1.4).

These challenges are described in more detail below.

3.1.1 Commercial framework for distributed generation

The current framework creates conflicting and, at times, distorted incentives for DG investment. On the one hand, cross-subsidisation between DG and non-DG customers might over-incentivise investment in DG, because DG customers pay less toward fixed grid costs even though they continue to rely on the grid, and the shortfall is borne by non-DG customers through higher tariffs. On the other hand, volatility in the FIT creates uncertainty, which might deter customers from investing in DG.

Cross-subsidisation between DG and non-DG customers

Under the current tariff structure, there is misalignment between how costs are incurred and how they are recovered. BELCO recovers most of its fixed costs through variable energy consumption charges rather than fixed charges (see Section 4.1.3 on misalignment in the retail tariff structure).[71]

In general, residential and other small customers already tend to pay below their cost of service, but the effect is more pronounced for those with DG. DG customers reduce their grid consumption and thus, their contribution to cost recovery, even though they continue to rely on the grid for backup supply and network services. As a result, residential and small commercial DG customers tend to contribute less toward system costs than comparable non-DG customers, effectively leading to cross-subsidisation.

A 2024 DG study confirms this by comparing the average annual bill paid by DG customers and non-DG customers within each class with the full cost of service they impose on the grid. The analysis found that DG customers generally pay less relative to their cost of service than their non-DG counterparts. For example, the average DG residential customer pays about $1,456 per year below the costs that BELCO incurs to serve them, compared with $40 per year below cost of service for non-DG residential customers.[72]

Two features of the tariff drive this. First, residential and small commercial customers are subject to an inclining-block energy tariff under which they pay a higher rate per kWh as their grid

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[71] RA. October 2022. “Retail Tariff Design Restructuring Report,” pp.6-7. Link

[72] The average non-DG demand customer pays $34,529 more per year than the cost it incurs on the grid, while the average DG demand customer pays approximately $19,935 more per year.

Ricardo. 2024. “Distributed generation in Bermuda: costs vs rates”.

consumption increases.[73] Because DG reduces grid consumption, DG customers can move into a lower block and pay a lower per-kWh rate.

Second, residential customers pay a fixed monthly graduated facility charge (GFC), which is structured into five tiers based on daily consumption.[74] DG customers are automatically placed in GFC Tier 3 regardless of their actual consumption.[75] This means DG customers can end up paying a lower GFC tier, and therefore a smaller contribution to fixed cost recovery, than they paid before installing DG. Other customer categories do not benefit from this effect because they pay a fixed facility charge regardless of consumption.

FIT volatility

Currently, the Standard Contract[76] between BELCO and DG customers allows such customers to self-consume the electricity their systems generate and sell any excess to BELCO at the FIT set by the RA.[77,78] The RA calculates the FIT and adjusts it quarterly using the following formula:[79]

$$FiT\left(\frac{\$}{kWh}\right) \leq \frac{\text{avoided cost of generation}\left(\frac{\$}{\text{Period}}\right) + \text{economic benefits}\left(\frac{\$}{\text{Period}}\right) + \text{adjustments}(\$)}{\text{forecast system exports (or production) by distributed generators}\left(\frac{kWh}{\text{Period}}\right)}$$

Because the FIT is updated quarterly based on BELCO's avoided cost of generation, it is closely correlated with fuel prices, which themselves have been volatile. As Figure 3.1 shows, the FIT has ranged from $0.103 per kWh to $0.192 per kWh between Q4 2023 and Q2 2026, with quarterly changes as great as 46 percent (between Q4 2023 and Q1 2024). For a customer making a multi-year investment decision in a DG system, that level of volatility in the revenue stream from exported generation makes the financials of the investment harder to assess and may deter uptake.

The volatility appears to have stabilised since 2025, as the FIT has been more stable, broadly mirroring the reduction in FAR volatility over the same period. This likely reflects BELCO's fuel stabilisation measures (see Section 4.2.2). However, these stabilising measures are not formalised in the FIT methodology and depend on the continued effectiveness of BELCO's fuel cost management. As a result, it does not, in itself, provide DG customers with multi-year revenue certainty to support investment decisions over a 7- to 10-year horizon.

73 RA. December 2025. "Retail Tariff Review Public Report," p. 15 Link

74 RA. December 2025. "Retail Tariff Review Public Report," p. 15 Link

75 RA. October 2022. "Retail Tariff Design Restructuring Report," p. 21 Link

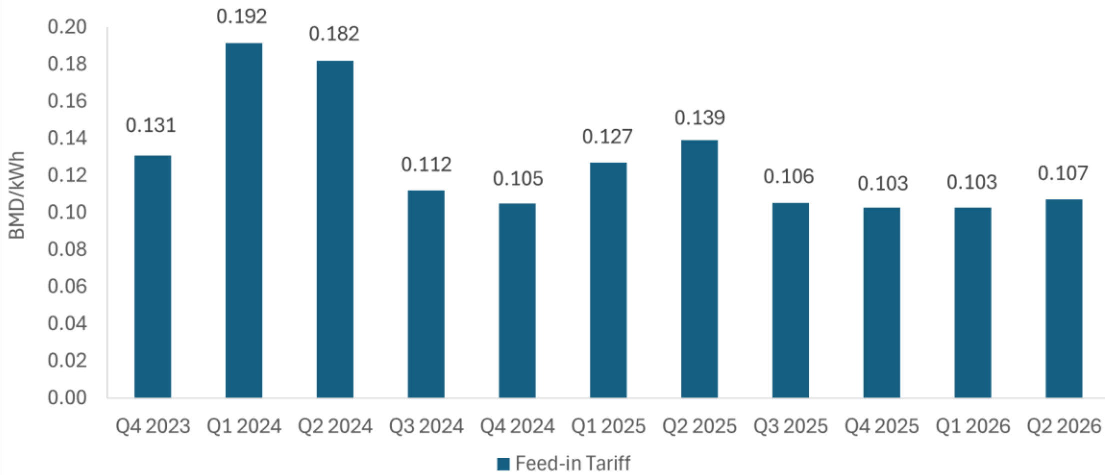
76 The Electricity Act defines a Standard Contract as a contract between a DG customer and the TD&R Licensee (Government of Bermuda. "Electricity Act 2016," Sections 49). The Standard Contract is also called Interconnection Agreement and these terms are, in practice, used interchangeably (RA. "Order #20180816. Decision and Order setting standard contract template" Link)

77 The Electricity Act requires any third party who wishes to engage in distributed generation to apply for a Standard Contract with BELCO. Government of Bermuda. "Electricity Act 2016," Sections 49(1)-(2). Link

78 RA. October 2022. "Understanding your BELCO bill: Feed-in Tariff" Link

79 RA. September 2023. "Feed-in Tariff General Determination," Annex 1, paragraph 7 Link

Figure 3.1: Quarterly FIT



Source: BELCO. "Feed-in Tariff Rates". Link

3.1.2 Grid stability

The current framework gives limited consideration to DG and its impact on the grid. The Electricity Act sets out only two DG-related requirements: It requires the IRP to include proposed limits for total DG capacity over the planning period[80] and allows BELCO to execute a Standard Contract with a DG customer as long as total DG capacity remains below the limit set in the approved IRP in effect.[81] Condition 22.4 of BELCO's Licence also requires BELCO to review the Grid Code periodically (every 5 years or less, as determined by the RA),[82] but this obligation does not currently ensure that the Code reflects the technical requirements needed to accommodate growing DG capacity.

The current IRP process itself does not give BELCO the information it needs to manage grid stability risks proactively:

- The 2019 IRP and draft 2023 IRP lack an analysis of the hosting capacity of the distribution grid. Both IRPs include proposed limits on total DG capacity (30MW in the 2019 IRP,[83] and a forecast range of 30 to 40MW in the draft 2023 IRP).[84] However, both documents explicitly state that these limits are indicative and should be validated through detailed locational system studies at the distribution level. Those studies, which would determine how much

80 Government of Bermuda. "Electricity Act 2016," Section 40.

81 Government of Bermuda. "Electricity Act 2016," Section 49(2)(a).

82 RA. August 2017. "Transmission Distribution & Retail Licence." Link

83 RA. June 2019. "Bermuda Integrated Resource Plan," Section 6.12. Link.

84 RA. July 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," Section 5.7.2. Link

DG can be connected to specific feeders without causing voltage violations or overloading, have not been carried out.[85]

- The IRPs also do not analyse mitigation options for the grid stability risks they identify. Both IRPs acknowledge that grid instability, particularly frequency response and loss of system inertia, becomes a concern at high levels of renewable penetration, and that solutions such as battery storage providing frequency response, and synthetic inertia from inverter-based resources, require further investigation. Neither IRP investigates these solutions in detail.[86]

The DG approval process screens individual installations but is not anchored in a system-wide view of how much DG the grid can absorb. Applicants must submit a feasibility study application to BELCO, which sets out the characteristics of the DG equipment being considered.[87] BELCO conducts the feasibility study and provides the results, setting out the parameters within which the system must be designed. The customer then submits a planning permit application to the Department of Planning (DoP) within those parameters, including BELCO's feasibility study results confirming that the proposed DG system is compatible with the distribution network.[88] Once DoP grants the permit, the customer installs and commissions the system and must obtain an occupancy certificate from DoP. After obtaining the certificate, the customer submits a final interconnection request to BELCO.[89]

Figure 3.2 shows the current DG approval process for a system between 400 and 1,000 square feet (sq.ft.), with indicative timelines. Systems smaller than 400 sq.ft. require BELCO's screening too, but only need a building permit from the DoP, which is granted instantly, after which the customer can proceed with installation. Systems larger than 1,000 sq. ft. are subject to the full development application process, with the DoP's Development Approval Board reviewing the application.

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85 RA. June 2019. "Bermuda Integrated Resource Plan," p. 60. Link; RA. July 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," p. 47. Link

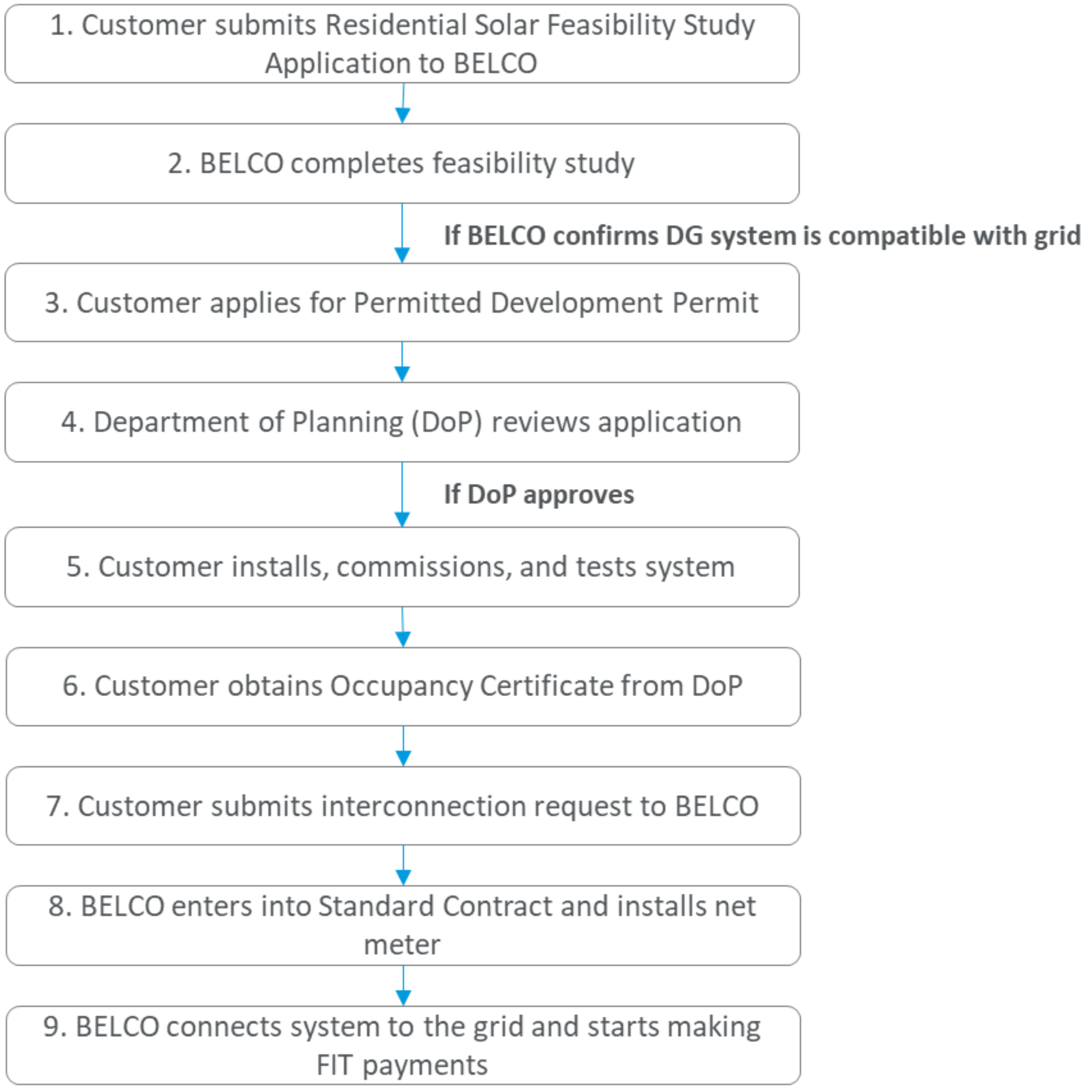
86 RA. June 2019. "Bermuda Integrated Resource Plan," p. 59. Link; RA. July 2024. "Integrated Resource Plan (IRP) Proposal Invitation to Comment," p. 142. Link

87 BELCO. April 2026. «RES Application Form » Link

88 Department of Planning. September 2024. « Policy clarifications and updates for solar PV applications & installations » Link

89 BELCO. "Solar Connection". Link

Figure 3.2: Current approval process for a DG system between 400 and 1,000 sq.ft.



Note: PDP refers to Permitted Development Permit. Although BELCO's application is titled "Residential Solar Feasibility Study Application," BELCO's eligibility criteria are based on system size, not customer type. The process applies to distributed solar systems up to 500kW, including non-residential systems that meet the applicable size criteria.
Sources: BELCO. 2026. "Solar Connection". Link; Department of Planning. "Solar photovoltaic rebate initiative (SPRI)". Link; Department of Planning. "Guide to Submitting Planning Applications". Link; Department of Planning. "A Guide to Permitted Development Permits

(PDPs)". Link; Government of Bermuda. December 2024. "Information and Updates for the Department of Planning". Link; Regulatory Authority. "Decision and order setting standard contract template," Annex 1. Link.

This sequencing addresses some of the technical screening risks that arose from DoP approving installations without prior assessment by BELCO, as was the case until October 2024.[90] However, three structural limitations remain:

- BELCO assesses each application against the distribution constraints visible to it at the time, rather than against a broader view of how much DG can be connected to specific feeders or circuits. Without the locational hosting capacity studies described above, BELCO lacks a system-wide view of what the grid can accommodate, making it difficult to manage cumulative impacts on grid stability as DG capacity grows.
- BELCO must conduct a bespoke technical assessment for each application, adding time to the process, with timelines of up to 70 business days for the feasibility study alone.[91] The absence of a pre-approved list of DG equipment requires BELCO to assess the grid compatibility of each specific installation, rather than relying on a pre-vetted list of equipment known to be compatible with the grid.[92]
- The Department of Energy and RA are not systematically informed of pending DG applications, limiting the Government's visibility over the pipeline of DG installations and their cumulative impact.

3.1.3 Increase in system costs

If the planning gaps described above are left unaddressed, DG expansion is likely to raise total system costs in several ways.

Without locational hosting-capacity studies, DG can cluster on specific feeders and trigger voltage violations, thermal overloads, or reverse power flow. BELCO would have to address these problems through unplanned reinforcements, such as transformer upgrades, voltage regulation, and changes to the protection scheme. Unplanned reinforcements will typically cost significantly more than equivalent upgrades planned and sequenced through the IRP.

The cost of reserves, ramping, and frequency response is also likely to rise. Variable DG output requires more spinning reserve and faster ramping from BELCO's thermal fleet, which can force units to run at lower efficiency. As DG penetration grows, the system will increasingly need storage to maintain frequency stability.[93] Like grid upgrades, procuring these reactively is likely to be more expensive than procuring them through a planned, sequenced approach informed by the IRP.

Once feeder-level hosting capacity is exceeded, BELCO might also need to curtail DG output to maintain grid stability. Curtailment will force BELCO to replace low-cost renewable energy with

[90] Department of Planning. September 2024. « Policy clarifications and updates for solar PV applications & installations » Link

[91] BELCO. "Solar Connection." Residential Distributed Solar Connection Process, Steps 1–2. Link

[92] Meeting with BELCO. April 2026

[93] Meeting with BELCO. April 2026

more expensive thermal generation, while DG customers lose the FIT revenue they had expected.[94]

3.1.4 BELCO's financial viability

If left unaddressed, the combined effect of the challenges described above will result in a self-reinforcing cycle that erodes BELCO's revenue base and accelerates further DG adoption: the utility death spiral.

The utility death spiral dynamic arises because most of BELCO's costs are fixed, while a majority of revenue is recovered through volumetric charges. As DG adoption increases, customers purchase less electricity from the grid. Although this reduces sales, it does not reduce the underlying cost of maintaining generation capacity and network infrastructure required to ensure reliable supply.

As a result, BELCO must recover its fixed costs from declining electricity sales volume, leading to higher tariffs for remaining grid consumption. These higher tariffs, in turn, further improve the relative economics of DG, encouraging additional customers to self-generate and reduce their reliance on the grid.

Over time, this cycle can erode the utility's revenue base and increase upward pressure on tariffs, particularly for customers who do not or cannot adopt DG. Left unchecked, it may also undermine investment signals needed to maintain system reliability and modernise infrastructure.

BELCO's data already show signs of this dynamic. Its electricity sales have decreased by 13 percent since 2010,[95] and BELCO estimates that DG has led to a 2 percent increase in bundled rates.[96] While these effects remain relatively modest at current levels of DG penetration, they are likely to become more pronounced as DG capacity continues to grow. Without changes to tariff design and system planning, the current framework risks shifting an increasing share of system costs onto a smaller customer base, increasing affordability concerns and financial pressure on the utility.

3.2 Recommendations for the sustainable expansion of distributed generation

Bermuda's approach to DG should ensure that it contributes to lower system costs and improved resilience, without undermining grid stability or placing disproportionate costs on non-DG customers. To achieve this, the Government can:

- Integrate DG planning and forecasts into the system planning (Section 3.2.1) and strengthen the DG interconnection approval process (Section 3.2.2) to ensure that the expansion of DG is done in a least-cost way while maintaining grid stability;

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94 Section 6.2 of BELCO's Standard Contract template for Renewable Interconnection Agreement states that customers are compensated only for electricity exported to BELCO, while Section 8.3 provides that customers are "not entitled to any form of compensation" if BELCO temporarily disconnects or reduces facility output.

RA. 2018. "Annex D – BELCO Solar PV Technical Requirements (Renewable Energy Interconnection Agreement)". Link

95 Meeting with BELCO. April 2026

96 BELCO. "Utility Spiral and Energy Transition Planning & Operations," Presentation shared by BELCO in May 2026.

- Establish a fixed FIT in the Standard Contract to give DG customers revenue certainty (Section 3.2.3). BELCO's recently introduced fuel cost stabilisation mechanism, together with further fuel-hedging measures, would also help give DG customers revenue certainty by addressing the FIT's volatility at its source. These are discussed in Section 4.2.2; and
- Reduce cross-subsidisation between DG and non-DG customers (Section 3.2.4), drawing on the retail tariff design restructuring options that the RA has already developed to improve cost-reflectivity across customer classes, and on additional options targeted specifically at DG customers. Because retail tariff design sits within the RA's remit, we discuss the RA's options at a high level without making a specific recommendation on tariff design.

How to implement these recommendations is described below.

3.2.1 Integrate distributed generation into the IRP

DG is now de facto part of Bermuda's generation mix and should be planned as such. To do this, the IRP should include DG as one of the supply resources to determine the amount of DG that fits into the least-cost generation mix. The IRP also needs to identify grid upgrades and storage investments needed to allow DG to expand without compromising system stability and reliability.

To implement this approach, the Government may amend Section 40(2) of the Electricity Act to require that the RA's IRP Proposal Guidance require the IRP to:

- Forecast the DG capacity expected to be installed over the planning period;
- Model the impact of forecasted DG on grid operations, system stability, load management, and system costs, including the necessary technical studies;
- Define the cap beyond which additional grid stabilisation investments must be budgeted and procured; and
- Use data from a national Distributed Generation Register.

The Government may also direct the Department of Energy to establish and maintain that Register, recording all approved installations, their cumulative capacity, and their geographic location.

Other comparable jurisdictions have integrated DG planning into the IRP in this way as shown in Box 3.1.

Box 3.1: Examples of integrating DG into sector planning in other jurisdictions

Barbados

Barbados has seen rapid DG growth, with installed distributed solar increasing from roughly 3.5MW in 2014 to over 100MW in 2024.[97,98] In response, its 2021 IRP explicitly treats distributed solar as a distinct capacity category rather than an external or residual factor.[99] To ensure the plan remains current, the IRP recommends that its assumptions and parameters, including those relating to DG uptake, be reviewed and updated at least every 2 years.

A 2022 Action Plan operationalises the IRP through several mechanisms for ongoing DG monitoring and forecasting. This includes:[100]

- **Coordinated forecasting across entities:** Different entities are responsible for forecasting DG-related activity, including new connections, licence applications, and required inspections, ensuring that all projections are consistent and aligned with the IRP capacity planning.
- **Centralised data tracking:** Three dashboards continuously track historical, current, and forecast DG data, covering grid operations, licence applications, and customer connections.
- **System visibility:** The utility develops day-ahead solar and wind production prediction modules and publicly reports distribution hosting capacity.
- **Planning for system impacts:** DG growth is explicitly linked to system needs, recognising that high levels of daytime solar generation can create midday surpluses and steep evening ramp-up requirements. This drives the need for additional flexibility, including battery storage and vehicle-to-grid integration.

Belize

Belize takes a similarly rigorous approach through its 2022 Least Cost Expansion Plan, in which DG is modelled as a formal demand-side resource that reduces the net load on the utility, with the capacity expansion plan optimised against the residual demand. Belize's plan forecasts the uptake of commercial customer rooftop solar, projecting that up to 50 percent of commercial customers will switch to self-supply over the planning horizon, equivalent to around 10 percent of total system demand by 2042. The forecast is spatially disaggregated by load centre and substation, feeding directly into load flow modelling. DG's competitiveness is assessed against Belize Electricity Limited's tariff rates and stress-tested against storage combinations, with the results directly influencing how much utility-scale generation needs to be procured.[101]

3.2.2 Strengthen the DG interconnection approval process

As DG capacity increases, interconnection processes should evolve from an administrative approval system to a more coordinated process, which considers grid impact and other system stability risks. The Government can achieve this by:

- **Ensuring early and systematic information sharing across entities:** For example, Government can require the Department of Planning to notify the Department of Energy and the RA of DG interconnection applications within a reasonable timeframe, providing

[97] NREL. 2015. "Energy Transition Initiative: Island Energy Snapshot — Barbados," p.3. Link.

[98] Government of Barbados. 2025. "Barbados 2025 Second Nationally Determined Contribution,"p. 17. Link.

[99] Mott MacDonald. June 2021. "Integrated Resource & Resiliency Plan for Barbados". Link

[100] Government of Barbados. 2021. "Action Plan and Roadmap – Final Report". Link

[101] Belize Electricity. 2022. "Integrated Resource Plan," pp. 103-110. Link

technical details, including system capacity, type, and location. Formalising this process (through a Memorandum of Understanding between departments, for example) would allow for more visibility over projected DG uptake and allow the cumulative impacts to be assessed and considered.

- **Introducing standardised technical requirements and pre-approved equipment:** Directing the RA to develop, in conjunction with BELCO, a list of pre-approved DG equipment to streamline the technical inspection and approval phase for BELCO. The list would identify systems known to be compatible with the grid and should be updated regularly (annually, for example) to keep pace with new technologies. This measure aligns with the draft NESP 2026 strategy under "Installation Standards and Compliance," which calls for clearer standards and compliance requirements for renewable energy equipment.[102]

Comparable jurisdictions have adopted similar approaches, as shown below in Box 3.2.

Box 3.2: Examples of strengthening DG interconnection processes in other jurisdictions

Hawaii

Hawaii has a standardised interconnection framework to manage high levels of rooftop solar. Its framework includes:

- **Pre-approved equipment lists:** Hawaiian Electric maintains a published Qualified Equipment List of certified advanced inverters approved for use across its interconnection programmes.
- **Defined technical requirements:** All DG equipment must be formally certified to perform grid-support utility-interactive inverter functions, and applicants are required to submit detailed test reports and firmware specifications.[103]

Barbados

Barbados embeds DG integration requirements in its Grid Code, providing a consistent, enforceable basis for interconnection. This includes:

- **Clear technical standards:** The Grid Code specifies connection requirements and performance standards that DG systems must comply with.
- **Regulatory approval of standards:** Technical requirements are reviewed and approved by the regulator.
- **Consistency across projects:** Customers face a predictable set of requirements, reducing uncertainty and delays.[104]

Although implemented through different mechanisms, these features in Hawaii and Barbados help to reduce approval timelines while ensuring that all connected systems comply with grid requirements.

3.2.3 Establish the feed-in tariff in the Standard Contract

The current FIT framework provides limited certainty to DG customers because it is updated quarterly based on avoided fuel costs. Customers who wish to install a DG system seek certainty

[102] Government of Bermuda. 2026. “The National Electricity Sector Policy of Bermuda: Consultation Draft,” Section 10.2. Link

[103] Hawaiian Electric Company, Inc. “Rule No. 14,” Appendix I, Rule 14H. Link

[104] BLPC. “Grid Code,”pp.36-55 and 56-121. Link

about the revenue they will receive from exported generation in order to make an investment decision. To address this, the FIT should be structured to provide predictable, long-term revenue certainty, while continuing to reflect underlying system costs.

This can be achieved by embedding a fixed FIT directly into the Standard Contract for a defined period (for example, 7 to 10 years), rather than relying on quarterly adjustments. Locking in the FIT at the time the contract is signed ensures that customers have visibility over expected revenues.

At the same time, the FIT level of new contracts should be reviewed and updated periodically to reflect changes in system costs and market conditions. This ensures that the framework continues to support an economically efficient level of DG investment over time.

To implement this approach, the Government can implement three coordinated measures:

- Amend Section 49 of the Electricity Act to require that the Standard Contract specify a fixed FIT to be determined by the RA.
- Direct the RA to amend the Standard Contract template for BELCO and DG customers accordingly. Section 6.2 of the Contract currently provides that "the Customer shall be compensated for the Facility's energy that is exported to BELCO in each month in the manner mandated or approved by the Regulatory Authority of Bermuda from time to time."[105] This would need to be amended with a fixed rate for a defined period.
- Direct the RA to revise its FIT-setting methodology so that the fixed FIT applied to new contracts reflects changes in system costs and is set at an appropriate level. Because Section 36 of the Electricity Act places the FIT methodology within the RA's remit, the Minister may not amend the methodology directly, but can issue a Ministerial direction requiring the RA to update it along the principles set out below:
  - The FIT should not exceed the avoided cost of generation, calculated as the average system marginal cost during daylight hours over the contract period and informed by the IRP. This is consistent with current practice and Section 36 of the Electricity Act; and
  - Within that cap, the FIT should be set at a level that ensures commercial viability without providing excessive returns. Where the avoided cost exceeds the level required to make DG economically viable, the FIT can be set closer to the minimum threshold needed to support investment, maintaining sufficient incentives while limiting overall system costs.

3.2.4 Ensure fair cost-recovery across DG and non-DG customers

The current retail tariff structure does not reflect the way system-wide costs are driven. While BELCO already applies fixed charges across customer classes, these recover only a small share of fixed costs, with the bulk of cost recovery still happening through volumetric energy charges. As a result, DG customers pay less without reducing their reliance on the grid. Restructuring these

[105] RA. "Order #20180816. Decision and Order setting standard contract template" Link

charges to be more cost-reflective would ensure that all customers contribute to the cost of the network and generation capacity required to maintain reliability.

The RA has developed four options to make the tariff structure more cost-reflective and reduce cross-subsidisation between customer classes, including DG and non-DG customer classes. These options are discussed in Section 4.2.3, as they cover general retail tariffs across all customer classes rather than being targeted specifically at DG customers.

The Cayman Islands offer a practical example of two DG programs that address how DG customers contribute to system costs:

- The Distributed Energy Resource (DER) programme applies a tariff structure designed specifically for DG customers. It includes fixed charges that ensure customers contribute to the cost of the grid and backup capacity, even as their purchases from the grid decrease. Like in Bermuda, DG customers under this programme self-consume their own generation and sell any excess to the utility; and
- The Consumer Owned Renewable Energy (CORE) programme takes a different approach through a buy-all/sell-all scheme. DG customers buy all their electricity from the grid and sell all their DG generation to the utility. This means their contribution to system costs does not change after installing DG. The trade-off is that, depending on the FIT, this model can reduce the direct savings from self-consumption, thereby disincentivising an otherwise optimal level of DG investment.

Box 3.3 below provides further details on the commercial structure of these DG programmes.

Box 3.3: Cayman Islands DG Framework

The Caribbean Utilities Company, Ltd. (CUC) administers two DG schemes with the oversight of the Utility Regulation and Competition Office (OfReg): the DER programme and the CORE programme.[106,107,108]

DER Programme

Systems eligible for the DER Programme are limited to 250kW or the customer's normal peak demand, whichever is lower.[109] DG customers self-consume and export excess energy to the grid. DG customers receive a separate credit for excess energy exported to the grid, credited monthly at the lower of:

- An avoided-cost-based rate (based on variable generation costs such as fuel, government fuel duty, and renewable energy components),[110] or
- The comparable energy purchase rate in the most recent renewable energy power purchase agreement (PPA).[111]

[106] CUC. "Monthly Demand Charge". Link; CUC. "Demand Rates". Link

[107] CUC. "DER Programme". Link

[108] CUC. "CORE Programme". Link

[109] OfReg. February 2023. "Ofreg releases 3MW of Distributed Generation Capacity to Consumer Owned Renewable Energy (CORE) and Distributed Energy Resources (DER) Programmes". Link

[110] CUC. July 2025. "DER Billing Rates". Link; CUC. "DER Programme". Link

[111] CUC. July 2025. "DER Billing Rates". Link; CUC. "DER Programme". Link

There are dedicated demand-based tariff classes that apply to DG customers under which they pay:

- Monthly facilities charge;
- Energy charge ($/kWh);
- Monthly demand charge ($/kW), based on the customer's highest recorded kW demand in the billing period, multiplied by approved $/kW; and
- Additional capacity charge ($/kW), based on the highest monthly peak demand over a rolling 24-month period, multiplied by approved $/kW rates.[112]

These charges are designed to recover generation, network, and standby capacity costs. Monthly demand and additional capacity charges for DER customers are updated through periodic Cost of Service Studies and the Rate Cap and Adjustment Mechanism (reviewed annually under Licence Condition 25), with all tariff changes subject to OfReg approval.[113]

By contrast, standard residential and general commercial customers are billed primarily on a volumetric ($/kWh) basis with no demand or capacity charges, while large commercial customers may face similar demand-based charges but not as a result of DG participation.

CORE programme:

Under the CORE Programme, Programme capacity is capped and allocated by OfReg. The most recent allocation (2024) provided 4.4MW of available capacity, with remaining availability of approximately 3,144kW (private sector) and 52kW (national housing) as of March 2026.[114]

CORE operates as a buy-all/sell-all scheme. DG customers remain on standard retail tariffs, consume all their electricity from the grid, and receive a separate FIT credit for all generation sold to the grid.[115]

OfReg sets FIT via determination (not a fixed formula). OfReg periodically revises the FIT to reflect policy objectives, such as increasing DG uptake, and prior methodology benchmarks (avoided cost, levelized cost, and target IRR for CORE subscribers).[116]

4 Retail tariffs

While the recommendations in the sections above contribute to reducing electricity costs and thus retail tariffs, there are measures the Government can take to help limit upward pressure on tariffs. This section assesses some of the main challenges in the current tariff framework (Section 4.1). In response to these challenges, this section proposes options to increase the transparency of the tariff-setting framework and further stabilise fuel costs (Section 4.2).

Additionally, this section compares options to make tariffs more cost-reflective that the RA has already developed. As the retail tariff design is the remit of the RA, this analysis discusses, at a high level, the options and their implications for reducing cross-subsidisation, but excludes recommendations on the tariff redesign itself.

112 CUC. July 2025. "DER Billing Rates". Link

113 CUC. "Metered Electricity Service". Accessed March 2026. Link

114 CUC. "CORE programme". Link

115 CUC. "Standard Billing Rates". Link

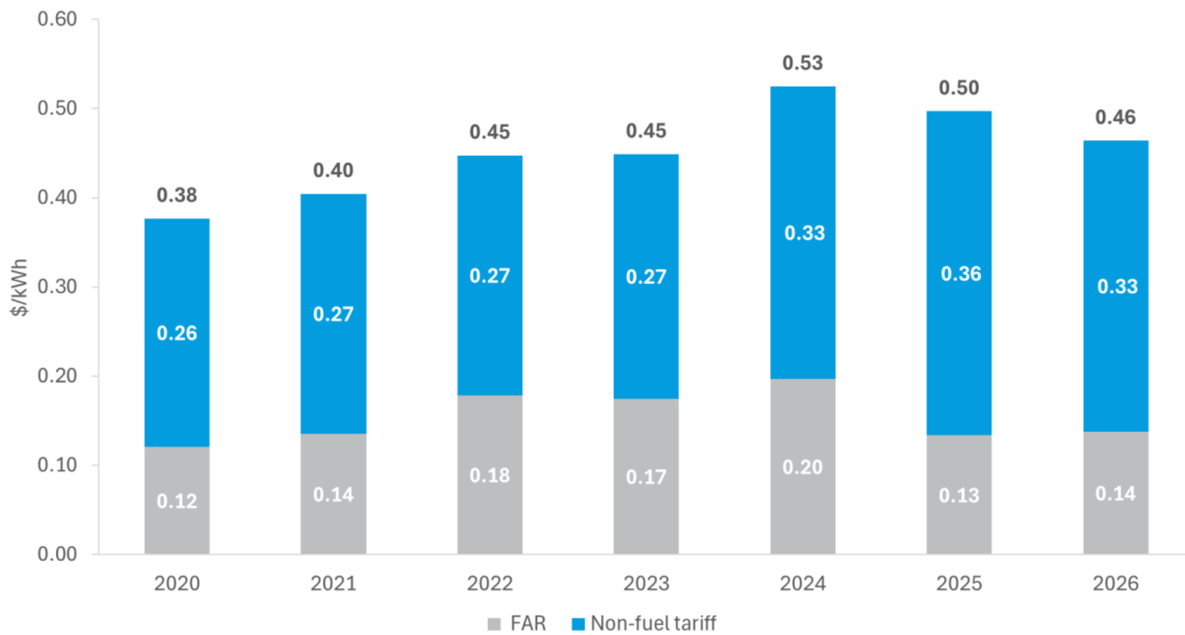
116 Ofreg. 2022. "Annual Plan". Link

4.1 Challenges under the current framework

Under Section 35 of the Electricity Act, retail electricity tariffs must allow BELCO to recover its reasonable and efficiently incurred costs, earn a reasonable return on investment, and meet required service standards. In practice, however, the retail tariff framework has not always delivered affordable or stable tariffs to end users.

The evolution of Bermuda's retail electricity tariff reflects both changes in underlying cost drivers and exposure to fuel price volatility. Figure 4.1 below shows the breakdown of the average tariff by its non-fuel component and the fuel adjustment rate (FAR).

Figure 4.1: Retail tariff breakdown by non-fuel tariff and FAR, 2020–2026



Note: For 2024-2026, the approved non-fuel tariff and FAR rate are based on the RA's Retail Tariff Review Public Reports. For 2020–2023, the non-fuel tariff is estimated using the non-fuel average base rate in the draft 2026 National Electricity Sector Policy, as the Retail Tariff Review Public Reports for this period do not provide a breakdown of the allowed revenue. The FAR for 2020-2023 reflects the annual average FAR calculated from BELCO's reported fuel adjustment rates. Totals may not match the sum of displayed values due to rounding; totals are based on unrounded data.
Source: RA Retail Tariff Review Public Reports, 2024–2026[117]; Draft 2026 NESP[118], BELCO[119]

The figure shows that the retail tariff has been on an upward trend since 2020. Bermuda's average electricity tariff is high by both international and regional standards (Section 4.1.1). At the same

[117] RA. July 2024. "Retail Tariff 2024 Public Report Final". Link; RA. January 2025. "Retail Tariff 2025 Public Report Final". Link; RA. December 2025. "Retail Tariff 2026 Public Report Final". Link

[118] Government of Bermuda. April 2026. "The National Electricity Sector Policy Consultation Draft" Figure 1. Link

[119] BELCO. Accessed May 2026. "Fuel Adjustment Rates". Link

time, customer bills have been volatile because a large share of the tariff is exposed to changes in fuel prices through the FAR, although the FAR has recently been more stable (Section 4.1.2).

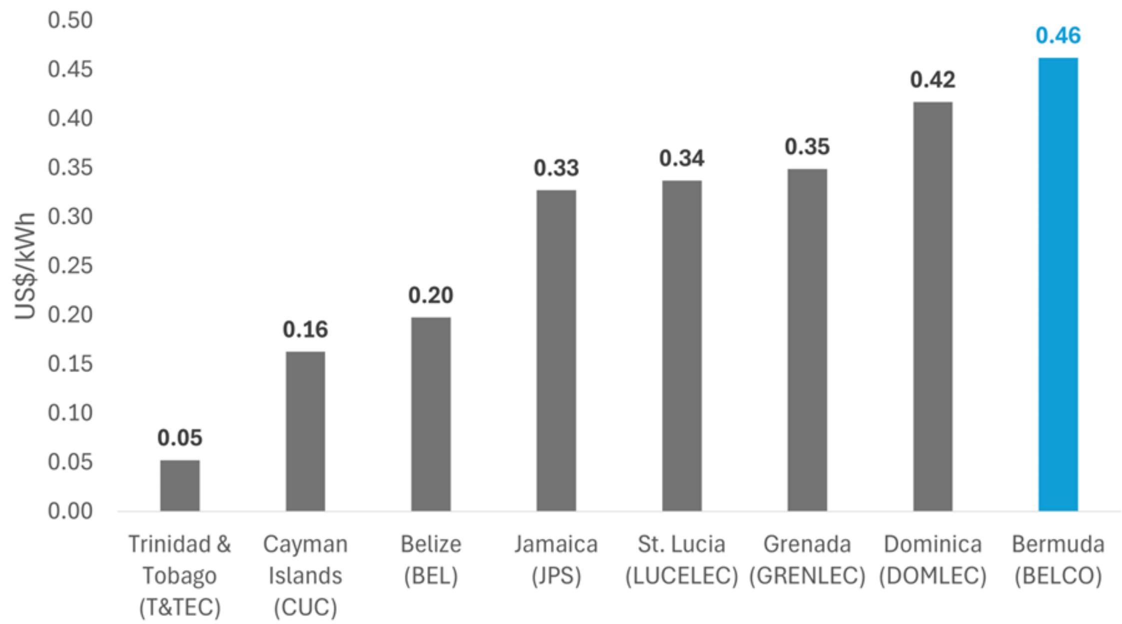
Beyond the level and volatility of the tariff, the way non-fuel costs are recovered through tariffs creates further challenges: Most of BELCO's fixed costs are recovered through volumetric charges (on a per kWh basis), which contributes to cross-subsidisation between customer classes and creates financial risks for BELCO as the system's demand profile changes as a result of increased DG and energy efficiency (Section 4.1.3).

4.1.1 Rates are relatively high

As of 2026, the average electricity tariff in Bermuda is $0.46 per kWh.[120] While electricity tariffs in fuel-dependent small-island systems are typically high relative to global averages, Bermuda's tariffs are high even compared with similar Caribbean jurisdictions, as shown in Figure 4.2 below.

[120] The average tariff is calculated based on BELCO's approved revenue allowance ($236,913,997) and forecasted total electricity sales (512,524MWh) for the 2026 tariff review period. RA. December 2025. "Retail Tariff Review Public Report," p. 8. Link

Figure 4.2: Benchmarking of Caribbean average electricity tariffs

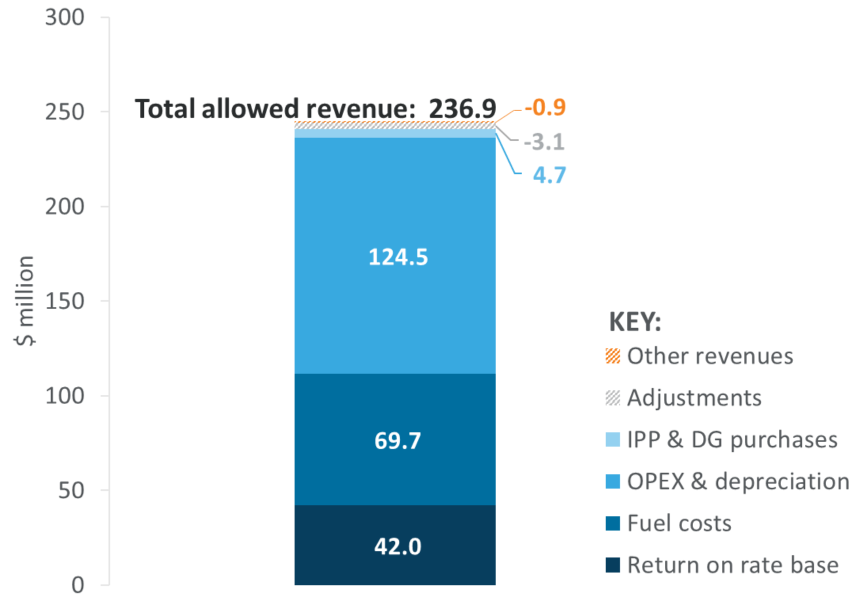


Notes: Average tariffs are calculated as total revenue from electricity sales divided by total electricity sales (kWh), based on the most recent available utility financials. It is worth noting that electricity tariffs are highly subsidized as the National Gas Company supplies to the utility (T&TEC) at highly subsidised rates.

Sources: RIC. "T&TEC's Annual Performance Indicator Report for the year 2021," pp. 3-10. Link; Energy Chamber of Trinidad and Tobago. 2017. "Understanding the electricity subsidy in T&T". Link; CUC. "Annual Report 2024," p.8. Link; JPS CO. "Annual Report 2024," p. 20. Link; LUCELEC. "Annual Report 2024," p. 56. Link; GRENLEC. "Annual Report 2024," p. 85. Link; DOMLEC. "Annual Report 2024," p. 94. Link

BELCO's retail tariff reflects the costs it is allowed to recover. Figure 4.3 breaks down its 2026 allowed revenue into its main components, showing that operating costs and depreciation make up the largest share (53 percent), followed by fuel costs (29 percent) and the return on rate base (18 percent).

Figure 4.3: Breakdown of BELCO's approved revenue allowance for 2026



Note: Other revenues and adjustments are negative values and represent deductions from the 2026 approved revenue allowance.
Source: RA. December 2025. "Retail Tariff Report Public Report". Link

According to Section 35(1) of the Electricity Act, the RA is responsible for determining the retail tariff in accordance with the methodology set by general determination, and the Electricity Act in general.

The retail tariff methodology must seek to enable BELCO to generate a total revenue that recovers the reasonable costs incurred to achieve service standards, in particular:

- Investment if it is prudently incurred and for which the investment is used and useful;
- Reasonable return on investment that is commensurate with the return in businesses with comparable risks and sufficient to attract needed capital;
- Reasonable and efficiently incurred OPEX, fuel procured for generation, and generation procured; and
- Other expenses, including Government authorisation fees, RA fees, and other statutory fees.[121]

The RA uses a building-blocks methodology to determine an ex-ante, forward-looking revenue cap. The RA calculates the revenue cap (or, in other words, the allowed revenue) using the formula:[122]

[121] Government of Bermuda. "Electricity Act 2016," Section 35(1)-(3).

[122] RA. January 2025. "Schedule to Regulatory Authority (Retail Tariff Methodology) General Determination 2025," Section 16. Link

Annual Allowed Revenue = OPEX + Depreciation + (Rate Base x Return on Rate Base) + Other Costs - Other Revenues ± Adjustments

Table 4.1 below explains how each building block is treated.

Table 4.1: Building blocks of BELCO's allowed revenue

Block	What it covers	How it is set	Treatment	If over- or underspend
OPEX	▪ Core network OPEX: Day-to-day running costs of the network ▪ Fees, charges, and taxes payable to public authorities (excluding fines and penalties)	▪ Core network OPEX: Ex-ante based on efficient cost forecast using a top-down or bottom-up approach ▪ Fees, charges, and taxes: actual costs	▪ Core network OPEX subject to an ex-post asymmetric incentive mechanism ▪ Fees and taxes are pass-through	▪ Underspend on core network OPEX is shared on a 40:60 basis, like capital expenses (CAPEX) ▪ Overspend is absorbed by BELCO, unless BELCO provides compelling evidence that the costs were efficient and reasonable
Depreciation	▪ Recovery of capital expenditure over the asset's economic life	▪ Straight-line depreciation applied to the rate base	▪ Cost allowance based on the RA's approved asset life assumptions	▪ No mechanism for over/under-spend; however, the RA may rebase the allowed revenue calculation if it considers the asset-life assumptions unreasonable
Return on rate base	▪ Allowed return on invested capital	▪ The rate base is valued using a historical cost accounting approach, meaning assets are recorded at the actual cost incurred at the time the CAPEX was made, with no adjustment for inflation or current market values ▪ Return on rate base is set using the nominal vanilla weighted average cost of capital (WACC) reviewed each period	▪ Ex-ante WACC set for the tariff review period ▪ Trigger mechanism applies to cost of equity if there are significant movements in capital markets (e.g. changes in the risk-free rate) ▪ Cost of debt and gearing are reassessed if BELCO undertakes significant changes to its capital structure	▪ The valuation of the rate base is subject to an over- or underspend mechanism ▪ Overspend in CAPEX is absorbed by BELCO, unless BELCO provides compelling evidence that overspend was prudently, efficiently, and reasonably incurred. Overspend is adjusted by reducing BELCO's allowed revenue in the next tariff period ▪ Underspend is shared on a 40:60 basis, with 60% of the benefit accruing to customers through reduced tariffs in the next tariff period under "Adjustments" and 40% retained by BELCO
Fuel costs	▪ The cost of purchasing and transporting fuel to BELCO for electricity generation	▪ Fuel prices are projected at the start of the tariff review period, and averaged throughout each quarter ▪ Deviations from the projections are adjusted every quarter when FAR is reviewed to reflect the	▪ Fuel costs are recovered in full through the FAR ▪ BELCO is required to show the FAR separately on customer bills	▪ The FAR is set to recover efficiently incurred fuel costs only ▪ Currently, this efficiency is measured through the heat rate target set by the RA and that BELCO is required to achieve

Block	What it covers	How it is set	Treatment	If over- or underspend
		actual cost incurred in the previous quarter		▪ If BELCO does not achieve the heat rate target within the tolerance range, the RA may impose a penalty on BELCO
Other costs	▪ Costs not captured in TD&R OPEX, depreciation, adjustments, or rate base ▪ Includes (but is not limited to) transfer pricing arrangements with BELCO's bulk generation business units and power procurement under PPAs with Independent Power Producers (IPPs)	▪ Actual costs incurred	▪ Costs are pass-through and recovered in full	▪ No mechanism for over/underspend. Other costs are passed through in full ▪ Variations between forecast and actual purchases (for example, from IPPs and DG) are reconciled in the next tariff review period under "Adjustments"
Other revenues	▪ Revenues earned outside the retail supply of electricity ▪ Includes connection fees, use of utility assets, and government relief	▪ Actual revenues earned	▪ Deducted from allowed revenue	▪ No mechanism for over/underspend. Other revenues are deducted in full ▪ Variations between forecast and actual may be reconciled under "Adjustments"
Adjustments	▪ True-up mechanisms (excluding FAR), performance regime, deferred revenue	▪ Determined by the RA based on actual versus forecast outcomes	▪ Annual true-up for IPP and DG purchases, sales variations, and performance regime outcomes	▪ Reconciles over- or under-recovery between forecast and actual costs and revenues

Source: RA. January 2025. "Schedule to RA (Retail Tariff Methodology) General Determination 2025". Link

The RA combines the building blocks revenue cap with an incentive framework to promote cost efficiency and maintain service quality. Under this incentive framework, BELCO is allowed to retain a share of any savings if its actual CAPEX and OPEX fall below the ex-ante allowances approved by the RA, as explained in Table 4.1. If expenses exceed the allowances, the RA can assess whether any overspend if prudent, reasonable, and efficient. Costs that do not meet these criteria may be disallowed and therefore, not recoverable through tariffs.[123]

In addition to cost efficiency incentives, BELCO is subject to performance-based incentives linked to service standards. The Electricity Act requires the RA to set standards for reliability, power quality, and customer service in line with industry best practice.[124] The standard indicators are set out in the RA (Service Standards Indicators for Electricity Licenses) General Determination 2019, and the RA sets targets for each tariff review period. To date, the RA has defined targets and tolerance ranges for some indicators, including SAIDI, SAIFI, and heat rate, based on BELCO's historical performance and benchmarking with comparable jurisdictions.[125] While the RA has indicated that additional performance targets will be introduced in due course,[126] no clear timeline has been established.

Performance against these standards is incorporated into the tariff-setting framework through the "adjustments" component of allowed revenue. Where BELCO fails to meet a standard within the defined tolerance range, its allowed revenue is reduced in the subsequent tariff period; where it exceeds the standard, it may benefit from an upward adjustment.[127] In certain cases, the RA may also require BELCO to compensate customers directly for service failures.[128]

Together, these mechanisms are intended to balance incentives and accountability. BELCO is given flexibility to manage its operations and identify efficiencies, while bearing the financial consequences of costs that are not prudent or efficient and of failing to meet required service standards. This is intended to ensure that only reasonable and efficiently incurred costs are passed through to customers.

BELCO reported that it has generally met or exceeded the RA's service standards targets.[129] One exception occurred in 2024, where the RA applied a penalty for failure to meet reliability standards.[130] No evidence was identified of other penalties being imposed for non-compliance with service standards.

[123] RA. January 2025. "Retail Tariff Review 2026-2027 – Information Request #1".

[124] Government of Bermuda. "Electricity Act 2016," Section 34.

[125] RA. April 2029. "Service Standards Indicators for Electricity Licensees," Section 55. Link

[126] RA. February 2026. "Service Standards Indicators – Performance Targets 2026". Link

[127] RA. January 2025. "Schedule to Regulatory Authority (Retail Tariff Methodology) General Determination 2025". Link

[128] RA. 2019. "Service Standards Indicators for Electricity Licensees," Section 58. Link

[129] Meeting with BELCO. May 2026.

[130] RA. July 2024. "Retail Tariff Review," Section VI. Link.

Rate of return

As noted above, Section 35 of the Electricity Act requires that the RA's retail tariff methodology enable BELCO to earn "a reasonable return on investment that is commensurate with the return on investments in business undertakings with comparable risks, and that is sufficient to attract needed capital."[131]

The RA's retail tariff methodology defines the approach to estimate the allowed rate of return (ROR) and explains how each component of the ROR should be calculated. The ROR is determined using a nominal vanilla WACC.[132]

In applying this approach, BELCO may apply multiple methodologies to estimate a range for the cost of equity, such as the capital asset pricing model (CAPM), or a risk premium approach. This approach is relatively uncommon, as regulators typically require a single point estimate rather than a range.

The RA then conducts its own independent assessment of the cost of equity using similar methodologies. Rather than relying on a single model, the RA compares the results across these approaches and against BELCO's submitted range. This results in a range of plausible estimates for the cost of equity, rather than a single point value.

The methodology, however, does not explicitly define how this range is narrowed to a final estimate. In practice, the RA typically forms a recommended range based on its assessment and submits this to the Board of Commissioners, often proposing the midpoint as the basis for the allowed cost of equity. The Board then determines the final value as part of its overall decision on the allowed rate of return, balancing the need for BELCO to recover its cost of capital with the resulting impact on customer tariffs.[133]

The RA sets the cost of debt and capital structure separately, based on the characteristics of an efficiently financed notional entity. These components, together with the cost of equity, are combined to derive the allowed WACC, which is applied to the regulatory asset base to determine the return on capital.

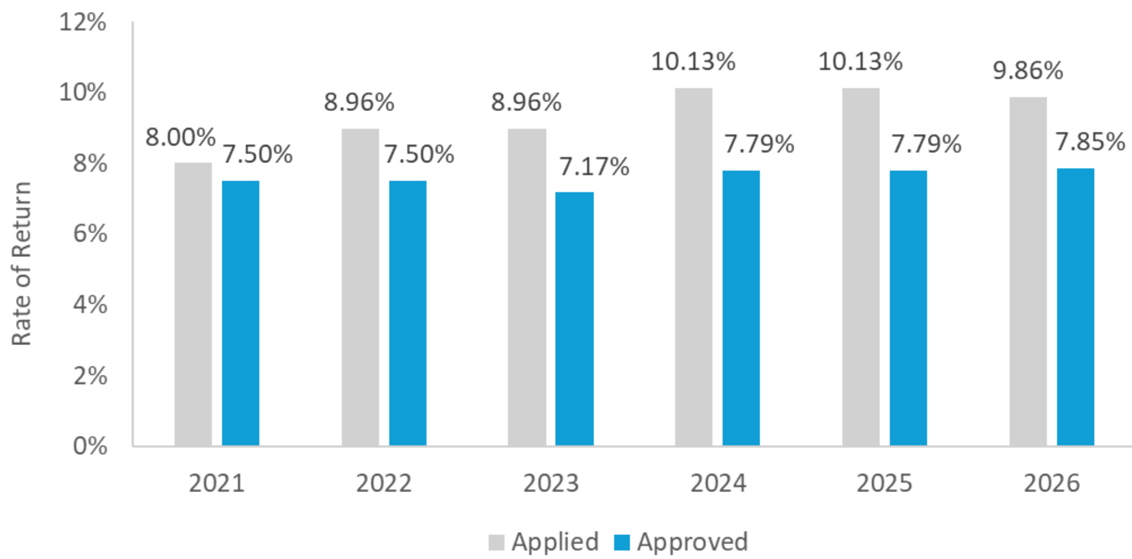
This process has resulted in an average allowed ROR of 7.6 percent between 2021 and 2026. This has been roughly 18 percent less than the ROR requested by BELCO on average, as shown in Figure 4.4 below.

[131] Government of Bermuda. July 2016. "Electricity Act 2016," Section 35.

[132] RA. January 2025. "Schedule to Regulatory Authority (Retail Tariff Methodology) General Determination 2025". Link

[133] Meeting with RA. May 2026

Figure 4.4: BELCO's applied and approved rate of return



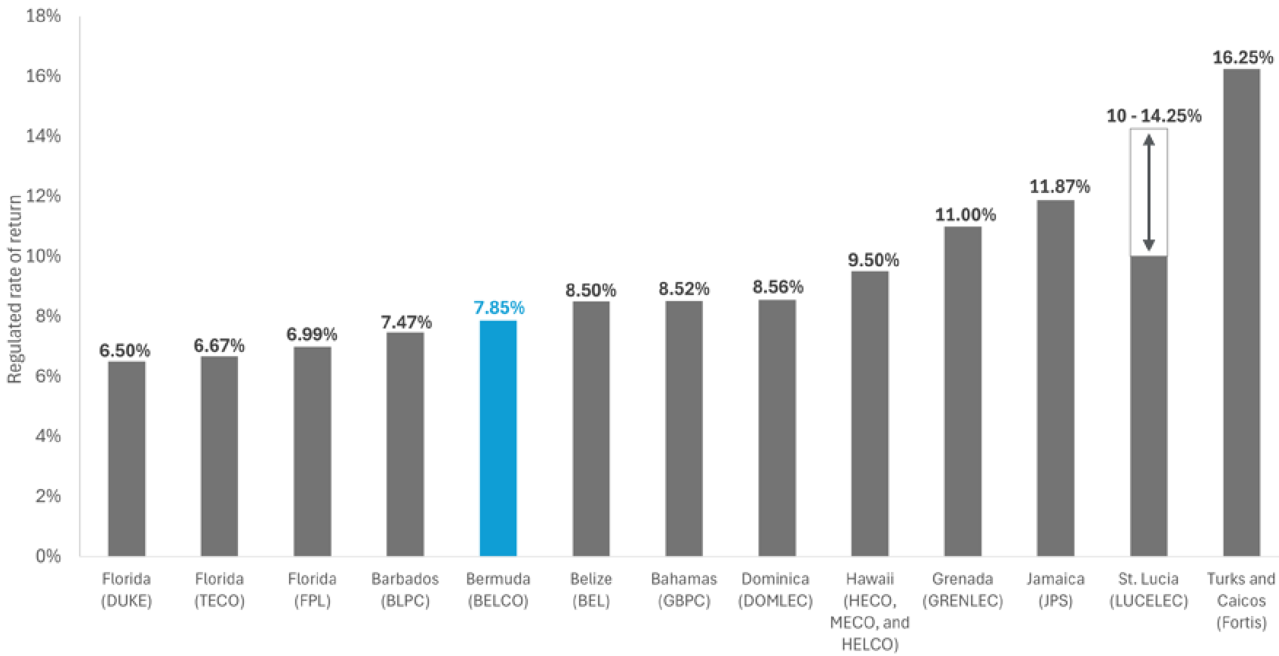
Note: The applied rate is typically the midpoint of the range proposed by BELCO.
Source: RA. Annual Tariff Determinations. Link

The RA's methodology appears to result in a reasonable ROR for BELCO compared to other jurisdictions. BELCO's allowed ROR for 2026 (7.85 percent)[134] is lower than the average ROR of 9.2 percent for benchmarks.[135] As shown in Figure 4.5 below, some comparable jurisdictions have allowed ROR as high as 16.25 percent.

[134] Calculated by averaging ROR over the last 6 years.
Bermuda RA. Accessed April 2026. "Annual Tariff Determinations. Link

[135] Calculated as the average of all allowed rates of returns for benchmarked countries. For Belize and St. Lucia, which define a range for the allowed ROR, the lower ends (6.5 percent and 10 percent, respectively) were used.

Figure 4.5: Benchmarking: Allowed rate of return



Notes: *St. Lucia: Allowable Rate of Return is between 2-7 percent above the cost of the most recent long-term bonds issued by the Government of St. Lucia on the Regional Government Securities Market, with a minimum return of 10 percent. This resulted in an ROR range of 10.00 percent to 14.25 percent in 2024. Turks and Caicos: Two sets of documents provide inconsistent formulas for determining the revenue requirement, including the ROR. The allowed ROR shown on the graph is the average of the rates set out in the Take-Over Agreements for FortisTCI (now Pelican Energy TCI), which define an allowed ROR of 17.5 percent and 15 percent, depending on the island. In practice, however, FortisTCI has applied for rates of return well below these levels, indicating that the utility and the regulator apply the regime defined in the Electricity Ordinance rather than the Take-Over Agreements. For example, in its 2024 rate application, FortisTCI requested a rate base return of 6.2 percent (and 3.2 percent for its TCU operations), substantially below the 17.5 percent and 15 percent allowed under the Agreements. Data on the ROR ultimately approved by the regulator is not publicly available.*
Sources: *Florida Electric Utility Industry. "Statistics of the Florida Electric Utility Industry 2024," p. 13; FTC. 2024. "The Barbados Light & Power Company Limited's Application for Preapproval of Investments and Cost Recovery through the Clean Energy Transition Rider," p. 61; RA. December 2025. "Retail Tariff Review Public Report"; BEL. "2024 Full Tariff Review Proceedings," p. 18*
Emera. "2024 Annual Report," p. 25; IRC. April 2015. "Decision Document - Weighted Average Cost of Capital," p. 7; Hawaiian Electric. 2025. "Key Performance Metrics"; GRENLEC. "Annual Report 2024," p. 23.; OUR. JPS Co. "Rate Review 2019 – 2024," p.175; LUCELEC. "Annual Report 2024," p.32; South Caicos Take Over Agreement, Annex C, schedule 7; and Providenciales Take Over Agreement, Annex C, schedule 7.

The methodology used by the RA to calculate the ROR is consistent with comparable jurisdictions. The regulators in Trinidad & Tobago,[136] Dominica,[137] and Grenada[138] also use a nominal vanilla WACC and CAPM to estimate the return on equity, while Jamaica uses a pre-tax nominal WACC and CAPM.[139]

[136] RIC. 2020. "Framework & Approach for the Price Review for the Electricity Transmission & Distribution Sector (T&TEC)," p. 38. Link
[137] IRC. April 2015. "Decision Document - Weighted Average Cost of Capital," p. 7. Link
[138] GRENLEC. "Annual Report 2024," p. 23. Link
[139] OUR. JPS CO. "Rate Review 2019-2024," p.175. Link

However, the RA's methodology to set the ROR has been challenged before. In the case *BELCO vs RA (2024)*, BELCO challenged the RA's approved ROR (7.16 percent vs 8.96 percent requested for the tariff review period 2022-2023).[140] BELCO argued that the approved ROR did not meet the requirements of Section 35(2) of the Electricity Act, on the grounds that it was insufficient to reflect the risks of the business or attract capital.[141] BELCO also argued that the RA relied too heavily on a single methodology (CAPM), did not adequately consider alternative approaches or adjustments such as the Lambda country-risk factor, and failed to provide sufficient transparency into its decision-making process or to engage meaningfully with BELCO during that process.

In response, the RA argued that Section 35(2) and (4) of the Electricity Act apply to the tariff methodology as a whole, rather than the specific ROR decision.[142] The RA also maintained that the approved ROR fell within a reasonable range of estimates produced by its expert (6.78 to 8.22 percent), and that there is no requirement for the RA to apply multiple methodologies in reaching its decision. The RA also argued that comparisons should be made against a broader set of jurisdictions with similar risk profiles, rather than relying primarily on US utility benchmarks.[143]

The Supreme Court of Bermuda upheld the RA's decision, citing the following:

- The RA's interpretation of Section 35 was correct: it is the methodology, not the specific ROR, that must satisfy Sections 35(2) and (4) of the Electricity Act;
- BELCO had not asserted that the range calculated by the RA's expert (6.78 to 8.22 percent) was unreasonable;
- The RA's approved rate of return of 7.16 percent fell within the RA's expert's calculated range, indicating its reasonableness;
- BELCO's applied ROR of 8.96 percent was above the range determined by its own expert (7.58 to 8.87 percent); and
- There is no statutory requirement for the RA to apply multiple methodologies to calculate the cost of equity.[144]

This outcome is consistent with regulatory practice in other jurisdictions. Utilities have, in several cases, challenged allowed rates of return on the basis that they were too low to maintain financial integrity or attract capital. In these cases, courts have generally upheld the regulator's methodology.

For example, in the United States, the legal standard established in *Federal Power Commission v. Hope Natural Gas Co.* (1944)[145] is whether the overall return is sufficient to maintain the utility's financial integrity and attract capital. A ROR that falls below this standard may be considered as

[140] RA. May 2025. "The RA Saves Energy Consumers up to $90 Million". Link

[141] Supreme Court of Bermuda. February 2024. "Bermuda Electric Light Company Limited v. The RA (2022 No. 97 Civ)". Link

[142] Supreme Court of Bermuda. February 2024. "Bermuda Electric Light Company Limited v. The RA (2022 No. 97 Civ)". Link

[143] Supreme Court of Bermuda. February 2024. "Bermuda Electric Light Company Limited v. The RA (2022 No. 97 Civ)". Link

[144] Supreme Court of Bermuda. February 2024. "Bermuda Electric Light Company Limited v. The RA (2022 No. 97 Civ)". Link

[145] Supreme Court of the United States. June 1944. "Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944)". Link

"confiscatory" and therefore, unconstitutional.[146] The US Supreme Court reaffirmed the principle in *Duquesne Light Co. v. Barasch* (1989), where utilities challenged their rates as confiscatory after the regulator disallowed certain expenses. Applying the Hope standard, the Court upheld the ROR on the basis that the overall return remained sufficient to attract capital.[147]

Similarly, in the United Kingdom, regulatory determinations on the cost of capital have been upheld where they are considered reasonable. In 2021, nine electricity and gas network companies appealed the price control set by the Office of Gas and Electricity Markets (Ofgem) to the Competition and Markets Authority (CMA), arguing that the allowed return on equity was set too low.[148] The CMA ultimately upheld Ofgem's overall allowed return of 4.55 percent.

Recoverable expenses

The current governing party has committed to amending Section 35 of the Electricity Act to "remove or limit categories of recoverable expenses" with the objective of "prioritising affordability for Bermudians."[149]

As explained above, Section 35 of the Electricity Act establishes the principles governing cost recovery. In particular:

- Section 35(2) allows recovery of capital investment that is "prudently incurred and for which the investment is used and useful," together with a "reasonable return on investment that is commensurate with the return on investments in business undertakings with comparable risks, and that is sufficient to attract needed capital;"[150] and
- Section 35(3) provides for the recovery expenses "efficiently incurred," including operating expenses, fuel procured for generation, generation procured, and statutory fees.[151]

Despite these provisions, the Government has expressed concerns that the application of the Section 35 framework might result in BELCO recovering imprudent and inefficient expenses. For example, the Government has raised concerns about soot fallout from the North Power Station, directing the RA to take appropriate action to remedy the issue.[152] It has also supported the principle that customers should be reimbursed where costs associated with plant operation are found to have been unreasonably incurred, and that such costs should not be passed through to tariffs.[153]

The RA's application of the Section 35 framework has also been challenged by BELCO in the case *BELCO vs RA (2024)*. BELCO challenged the RA's disallowance of certain CAPEX and OPEX, arguing that the RA had not properly assessed whether the costs were prudently incurred. BELCO also

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[146] Energy Bar Association. 1991. "Constitutional Limits on Ratemaking". Link

[147] Supreme Court of the United States. May 1989. "Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989)". Link

[148] Competition and Markets Authority. October 2021. "Energy Appeals – Summary of Final Determination". Link

[149] Progressive Labour Party. February 2025. "Building a fairer, more stable, and affordable Bermuda". Link

[150] Government of Bermuda. "Electricity Act 2016," Section 35(2).

[151] Government of Bermuda. "Electricity Act 2016," Section 35(3).

[152] Royal Gazette. July 2023. "Belco told to clean up its act". Link

[153] Royal Gazette. December 2023. "Belco customers could be reimbursed for miscalculations". Link

contended that the RA's approach departed from established regulatory practice in North America, where prudence is typically assessed against the reasonableness of the decision at the time it was made, without the benefit of hindsight. In addition, BELCO argued that the RA's decision lacked transparency and that it was not given sufficient opportunity to engage with the RA's reasoning during the decision-making process.[154]

The RA argued that Section 35 requires the tariff methodology to enable recovery of reasonable and efficiently incurred costs, but does not guarantee recovery of all costs. It maintained that prudence must be assessed alongside reasonableness and efficiency, with the burden of proof resting on BELCO, and that it had provided BELCO with an adequate opportunity to justify its costs. On transparency, the RA noted that it is required to give due regard, but is not held to an absolute standard.[155]

The Supreme Court of Bermuda upheld the RA's position, confirming that the statutory requirement applies to the methodology rather than individual cost determinations.[156]

The RA has since revised its methodology for evaluating the reasonableness, efficiency, and prudency of CAPEX, and the reasonableness and efficiency of OPEX. Before, the RA considered total CAPEX and OPEX. The RA now uses a more detailed bottom-up approach, assessing individual CAPEX and OPEX items using the tests explained below.[157]

However, these criteria are not yet fully codified in a General Determination. As a result, while the approach is clearer in practice, the absence of a consolidated framework may limit transparency and predictability.

Assessment of CAPEX

The RA conducts an ex-ante assessment of BELCO's proposed investments against two sets of criteria: reasonableness and efficiency. The reasonableness assessment focuses on the underlying need for the investment, the process used to identify and evaluate options, and the proposed delivery timeline. The efficiency assessment considers whether the proposed engineering solution is appropriate, cost-competitive, and sufficiently mature.[158]

The level of evidence required ex-ante depends on the asset category and value. Smaller projects (defined as below $500,000) require only a high-level justification (Short Project Description), while larger investments must be supported by more detailed technical, financial, and economic analysis.[159]

The RA conducts ex-post reviews of CAPEX on a case-by-case basis, assessing whether the costs were reasonable and efficient in light of the information available at the time the investment decision was made. For projects delivered within their approved budgets, costs are generally

[154] Supreme Court of Bermuda. "Civil Jurisdiction 2022: No. 97". Link

[155] Supreme Court of Bermuda. "Civil Jurisdiction 2022: No. 97". Link

[156] Supreme Court of Bermuda. "Civil Jurisdiction 2022: No. 97". Link

[157] Meeting with RA. May 2026

[158] RA. January 2025. "Retail Tariff Review 2026-2027 – Information Request #1". Link

[159] RA. January 2025. "Retail Tariff Review 2026-2027 – Information Request #1". Link

accepted without further review. Where overspending occurs, BELCO must provide evidence demonstrating that the additional expenditure was prudently incurred; otherwise, the excess may be disallowed through the regulatory adjustment mechanisms. For projects that were not previously approved, the RA requires supporting documentation proportionate to their size and materiality.[160]

Assessment of OPEX

As with CAPEX, the RA applies both ex-ante and ex-post scrutiny to OPEX. Ex-ante, the RA assesses BELCO's proposed OPEX against two principles:[161]

- Any increase to baseline costs (defined as the approved OPEX in the previous tariff review) driven by factors outside BELCO's reasonable control is treated as efficient by default; and
- Any other increase above the baseline is considered efficient only if BELCO provides compelling and consistent evidence of the nature and magnitude of all material contributing factors, substantiated by relevant documentation.

Ex-post, OPEX is subject to an asymmetric efficiency incentive mechanism explained in Section 4.1.1. Actual expenditure is compared against the approved allowance, with savings shared between BELCO and customers and overruns borne by BELCO unless it can demonstrate that the additional costs were reasonable and efficiently incurred.

4.1.2 Rates are exposed to fuel price volatility risk

Bermuda's electricity tariffs are exposed to changes in fuel prices and have been volatile in the past. Bermuda's generation mix is almost entirely dependent on fossil fuel, with about 90 percent of total generation coming from thermal resources, mostly heavy fuel oil (HFO).[162,163] As a result, fuel costs make up more than one-third of its OPEX[164] and account for 29 percent of BELCO's allowed revenue.[165]

Under the current framework, fuel costs are passed through to customers through the FAR, which is updated quarterly to reflect BELCO's actual fuel costs, as shown in Figure 4.6. The RA forecasts

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160 RA. January 2025. "Retail Tariff Review 2026-2027 – Information Request #1". Link

161 RA. January 2025. "Retail Tariff Review 2026-2027 – Information Request #1". Link

162 Calculated based on: February 2026 data on BELCO's gross generation (38,477MWh), purchased power from Tynes Bay (1,632MWh) and Solar Finger (625MWh), reported in BELCO. March 2026. "FAR Q2, 2026". Link; and an estimated monthly DG generation of 1,900MWh, calculated based on installed DG capacity (14.48MW) and a capacity factor of 18 percent. BELCO. May 2024. "2023 Integrated Resource Plan Proposal," p. 35.

163 HFO made up about 97 percent of BELCO's reported fuel consumption by volume over the previous 12 months. Calculated from the "Fuel Consumption Versus Kilowatt Hour Sales" table by summing monthly HFO and diesel fuel consumption for March 2025-February 2026. HFO consumption was 702,404 barrels; diesel consumption was 22,564 barrels.

BELCO. March 2026. "Fuel Adjustment Report Q2 2026," p.10.

164 Calculated as forecast fuel costs of $69,724,931 divided by the sum of approved OPEX (excluding pass through costs) of $124,506,263 and forecast fuel costs of $69,724,931. In the 2026 Retail Tariff Review, the RA discusses the approved OPEX allowance as including depreciation, labour and salary costs, and transport costs.

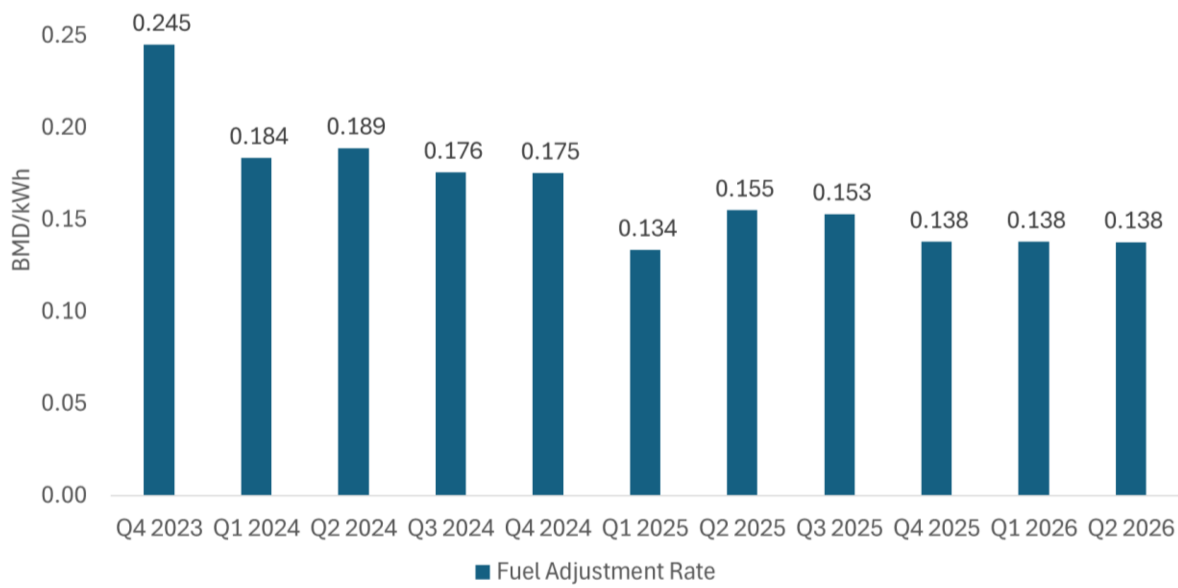
RA. 2025. "2026 Retail Tariff Review Public Report". Link

165 Calculated based on approved revenue allowance of $236,913,997 and forecasted fuel costs of $69,724,931. RA. 2025. "2026 Retail Tariff Review Public Report". Link

the FAR at the start of each tariff review period and averages the quarterly forecasts to obtain the annual forecast.

The FAR is then adjusted quarterly to reflect differences between forecast and actuals. At the end of each quarter, the RA reconciles actual costs against the forecast and spreads any over- or under-recovery across the remaining quarters of the tariff period. Any residual balance at the end of the period is carried forward into the next tariff review period.[166] As a result, changes in fuel prices are reflected in customer bills, typically with a short lag.

Figure 4.6: FAR (Q4 2023-Q2 2026)



Source: BELCO. "Fuel Adjustment Rates" Link

As Figure 4.2 above shows, the FAR's quarterly changes are relatively gradual and within a moderate range of $0.134 per kWh and $0.155 per kWh since 2025. However, there are a few exceptions when the forecast diverges significantly from actual fuel costs late in the tariff review period. In such cases, only one or two quarters remain to absorb the difference between forecast and actual fuel costs. Any under- or over-recovery must therefore be spread across a limited number of periods, resulting in sharper adjustments than would occur if the same amount were distributed over the full year.

This is what happened in Q4 2023. BELCO filed its quarterly FAR submission shortly before a material change in actual fuel prices, leaving a significant divergence between Q3 forecast and Q3 actuals. With only one quarter remaining in the tariff review period, the under-recovery was

166 Meeting with BELCO. May 2026.

absorbed in a single adjustment,[167] leading to a quarter-on-quarter FAR change of around 48 percent.[168] The Q4 2023 FAR report shows that the FAR was set to recover approximately a third of the year's total fuel cost in a single quarter.[169] Then, when the next tariff review period started in Q1 2024, the FAR fell by about 25 percent from Q4 2023, as the FIT was set against the full period's forecast fuel costs, with only a small under recovery rolled forward from 2023.[170]

Since 2025, BELCO has implemented a new fuel procurement and hedging strategy that partially smooths exposure. Between Q1 2025 and Q2 2026, the FAR remained within a relatively narrow range of $0.134 per kWh to $0.155 per kWh.[171] Rather than purchasing all fuel at spot market prices, BELCO enters into fixed-price supply contracts for a portion of its expected fuel needs. As a result, the FAR reflects a blended fuel cost, based on a mix of pre-purchased fuel and spot purchases. Figure 4.7 below compares the Platts market price index with BELCO's indexed fuel price, including pre-purchases and the FAR at the time of purchase.

This change has led to a noticeable reduction in tariff volatility. Between Q1 2023 and Q4 2024, it had a standard deviation of about $0.030 per kWh. Since 2025, the standard deviation has decreased to about $0.008 per kWh, resulting in a 73 percent decline in quarterly FAR volatility.[172]

While this approach has improved short-term stability, it relies on BELCO's operational decisions rather than on features embedded in the regulatory framework. The current pass-through mechanism continues to place most of the fuel price risk on customers, as changes in underlying fuel costs are ultimately reflected in the FAR. In addition, the tariff methodology does not set out a clear disallowance or incentive mechanism related to fuel procurement decisions, which may limit incentives for more active hedging or cost optimisation.

Additionally, BELCO has also taken steps to further reduce exposure to fuel price volatility by increasing fuel storage capacity from 135,000 to 180,000 barrels. This additional storage allows for greater flexibility in the timing of fuel purchases and may help smooth short-term price fluctuations.[173]

However, despite these improvements, the FAR remains structurally linked to global fuel prices. As shown in Figure 4.7, movements in the FAR continue to track underlying fuel price trends, reflecting the system's ongoing exposure to international energy markets. This means that, while

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[167] Meeting with RA. May 2026

[168] The FAR increased from $0.16513 per kWh in Q3 2023 to $0.24517 per kWh in Q4 2023, an increase of $0.08004 per kWh.
BELCO. 2026. "Fuel Adjustment Rates". Link

[169] Calculated based on 2023 fuel costs forecast of $92.1 million and FAR to be recovered in Q4 of $31.8 million.
BELCO. September 2023. "Fuel Adjustment Report Q4, 2023". Link

[170] BELCO. December 2023. "Fuel Adjustment Report Q1 2024". Link

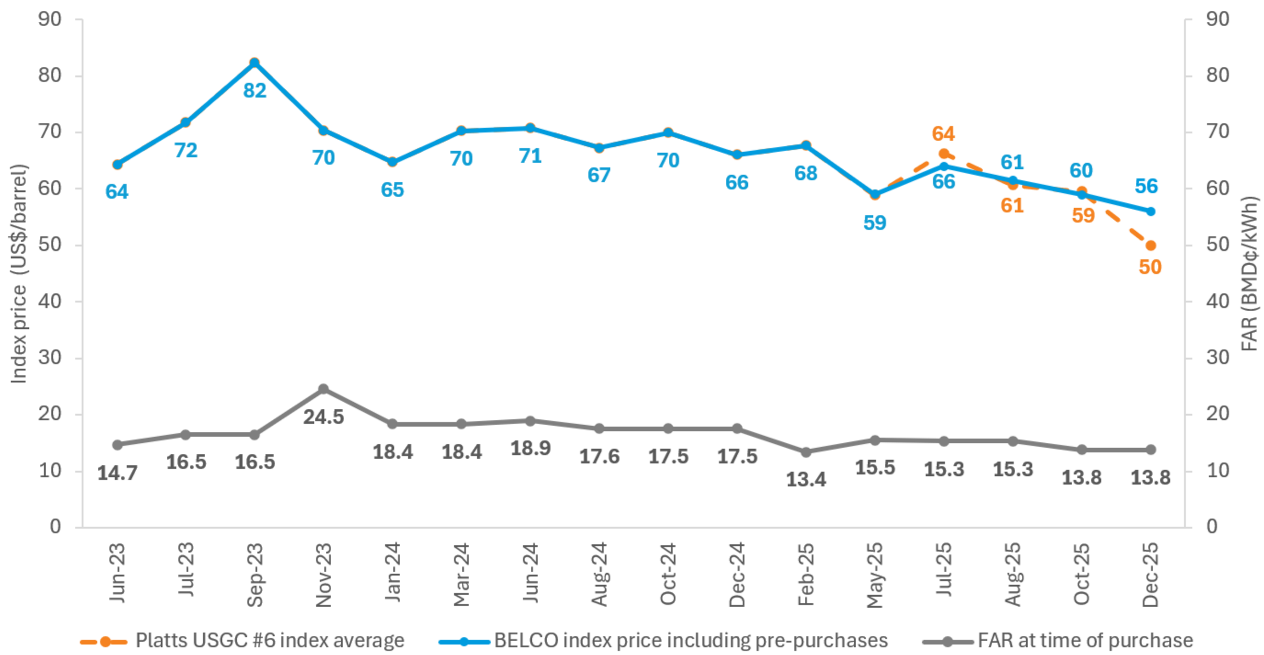
[171] BELCO. 2026. "Fuel Adjustment Rates". Link

[172] Based on quarterly FAR values from Q1 2023 to Q2 2026. Standard deviation calculated using quarterly FAR values in $ per kWh. Q1 2023-Q4 2024 standard deviation: $0.030 per kWh; Q1 2025-Q2 2026 standard deviation: $0.008 per kWh.
BELCO. 2026. "Fuel Adjustment Rates". Link

[173] Meeting with BELCO. May 2026

volatility has been reduced in recent periods, it has not been eliminated and could re-emerge if market conditions change.

Figure 4.7: Market fuel price index, BELCO index fuel price, and FAR at time of purchase



Notes: The Bermuda dollar is pegged to the U.S. dollar at a 1:1 exchange rate.
Sources: RA,[174] BELCO [175]

4.1.3 Cross-subsidisation between customer classes

The current tariff structure does not reflect how costs are incurred in the electricity system, which leads to cross-subsidisation between customer groups. As a result, some customers pay more than the cost of serving them, while others contribute less than their share, even though they all rely on the grid.

The mismatch starts with how BELCO's costs are made up. Most of BELCO's costs are fixed, driven by generation capacity and network infrastructure. These fixed costs represent approximately 80 percent of BELCO's total costs.[176] However, fixed charges account for only about 20 percent of total revenue; the remaining 80 percent of revenue is earned through variable energy charges (on a $ per kWh basis). This is the inverse of the underlying cost structure: the way BELCO earns revenue does not align with the way it incurs costs. As a result, customers' contributions to system

[174] RA. March 2026. "2026 Q2 FAR Report," p. 8. Link

[175] BELCO. "Fuel Adjustment Rate, Year-on-Year Comparison". Link

[176] Meeting with RA. April 2026

costs depend primarily on how much electricity they consume, rather than the actual cost BELCO incurs to serve them.

This misalignment creates cross-subsidisation effects between customer classes. The RA recognises that residential and small commercial customers generally pay below their cost of service, while larger customers pay above their costs of service, effectively subsidising smaller users.[177] As explained in Section 3.1.1, DG reinforces this cross-subsidisation because DG customers reduce their grid consumption and therefore contribute less to fixed-cost recovery, although they still use the grid's T&D infrastructure. Because BELCO's fixed costs remain the same, the recovery of these costs is shifted to customers who still consume fully from the grid.

This tariff design also weakens the price signals customers receive. Because most costs are recovered through volumetric charges, tariffs do not reflect the main drivers of system costs, such as peak demand or capacity requirements. As a result, customers have limited incentive to adjust consumption in ways that reduce system costs, such as shifting high load away from peak hours, and investment decisions (for example, in DG) may be driven partly by tariff design rather than the underlying cost drivers of the system.

These challenges are likely to become more pronounced as the system evolves. Increasing DG reduces grid consumption without reducing fixed costs, while changes in demand patterns, for example, through EV uptake or energy efficiency measures, can shift how customers use the network. Without changes to tariff design, these trends will continue to shift costs between customer groups and create upward pressure on tariffs for those who remain more reliant on the grid.

4.2 Recommendations for the retail tariff setting framework

The challenges described above point to a broader objective: A retail tariff framework that delivers stable, predictable, and cost-reflective tariffs for Bermuda's electricity consumers. A well-functioning retail tariff framework would set tariffs through a transparent process that recovers only reasonable and efficient costs, manage fuel price exposure to give customers more predictable bills, and align customer contributions more closely with the costs they impose on the system.

To achieve this, the Minister may use its existing power to issue general policy directions to the RA, combined with the RA's power to issue general determinations, without requiring any change to the law. Section 62(1) of the Regulatory Authority Act allows the RA to "make general determinations to carry out the provisions and purposes of this Act, sectoral legislation or any regulations."[178]

This section sets out practical measures for the Government. The first focuses on improving the transparency and predictability of tariff-setting methodology, particularly around how the RA determines the allowed rate of return and recoverable cost (Section 4.2.1). The second focuses on

[177] Regulatory Authority. October 2022. "Retail tariff design restructuring report". Link

[178] Government of Bermuda. "RA ACT 2011". Link

reducing the impact of fuel price volatility on customer bills by strengthening BELCO's fuel costs management strategy and adjusting how fuel costs are passed through to customers (Section 4.2.2). The third focuses on supporting a transition toward a more cost-reflective tariff structure that better aligns customer contributions with the costs they impose on the system (Section 4.2.3). As noted in Section 3.2, the RA has already developed options for a tariff redesign to improve cost-reflectivity and reduce cross-subsidisation. Because retail tariff design sits within the RA's remit, we discuss the RA's options at a high level without making a specific recommendation on tariff design.

4.2.1 Increase the transparency of the retail tariff setting framework

Limited transparency in how tariffs are determined makes it difficult to assess whether prices reflect efficient costs. Strengthening the clarity and predictability of the tariff-setting methodology would improve accountability and confidence in the framework.

Rate of return

The Minister may direct the RA to strengthen the transparency and clarity of the methodology to determine the allowed ROR.[179] In particular, the RA's Retail Tariff Methodology General Determination should clearly define the process for determining the allowed ROR, including steps from BELCO's submission through the RA's assessment, and ultimately to the Board's final decision. This could include:

- Criteria, evidence requirements, and decision-making process the RA shall use to assess whether costs are reasonable, prudent, and efficiently incurred;
- Establishing a single, clearly defined methodology for estimating the cost of equity, replacing the current approach that allows multiple methods to be applied; and
- Requiring a single point estimate of the ROR at each stage of the process, with BELCO submitting a single estimate to the RA, and the RA submitting a single recommended estimate to the Board for decision.

Recoverable expenses

Based on the available information, it is not possible to determine whether BELCO has recovered costs that are imprudent, inefficient, or unreasonable. This reflects limited transparency in how the RA assesses costs and how the outcomes of these assessments are reported.

While the RA is responsible for applying the tariff methodology and assessing cost prudency, the Government can take steps within its existing powers to improve visibility into these processes. In particular, the Government may:

[179] Section 8(1) of the Electricity Act provides that the Minister may, in accordance with sections 7 and 8 of the Regulatory Authority Act, issue Ministerial directions to the RA regarding any matter within the Minister's authority respecting the electricity sector. Government of Bermuda. "Electricity Act 2016". Section 8. Link; RA. 2011. "Regulatory Authority Act 2011," Sections 7-8. Link.

- Request information from the RA on the outcomes of its existing prudency reviews, including the methodology applied, the evidence used, and the basis for any cost disallowances; and
- If further assurance is required, direct the RA to undertake a more detailed review, including commissioning an independent prudency assessment of BELCO's costs.

This would allow the Government to better understand whether current tariffs reflect only reasonable and efficient costs consistent with the Electricity Act, and to identify whether further regulatory or policy action is required.

4.2.2 Stabilising tariffs

Volatility in tariffs is primarily driven by Bermuda's exposure to fuel prices. While reducing this exposure over the long term requires changes to the generation mix (see Section 2), there are measures to reduce the impact of fuel price fluctuations on customers' bills. These measures include improving how fuel costs are managed and adjusting how those costs are passed through to customers.

Strengthen BELCO's procurement and hedging strategy

BELCO has already taken steps to smooth short-term fuel price volatility through its procurement strategy, including the use of fixed-price supply contracts. However, this approach is not formalised in a transparent framework and lacks a proper accountability mechanism.

Strengthening the framework for managing fuel costs requires improving transparency, providing clearer guidance on how fuel price risk is managed, and increasing confidence that procurement decisions are aligned with policy objectives. To achieve this, the Government may direct the RA to take appropriate action, within its existing statutory powers, to proactively address fuel price volatility and strengthen fuel cost risk management in the sector. In response to such a direction, the RA could implement several options (or a combination of these):

- Develop and implement a fuel cost risk management framework, applicable to BELCO;
- Require BELCO to submit a formalised fuel hedging strategy for the RA's approval. This strategy should clearly define:
  - The objectives of the strategy. For example, the objective may be to reduce volatility in customer bills rather than minimise short-term fuel costs. Clearly defining objectives is important for maintaining accountability.
  - The instruments and contracting approaches BELCO plans to use. This may include fixed-price supply contracts, forward purchases, or financial hedging instruments such as swaps or options.
  - Limits on exposure, including the proportion of fuel that may be locked in at fixed prices, as well as any limits on contractual terms. These limits ensure that the strategy balances price stability with flexibility to respond to market conditions.

- Establish governance and reporting requirements related to the strategy.[180] This could include regular reporting on procurement performance, compliance with defined risk limits, and an assessment of how the strategy has affected fuel costs and tariff volatility.

Regulators in other island jurisdictions have implemented similar approaches. For example, in Barbados, the regulator approved a structured fuel hedging programme, which included fixed-price swaps for a portion of fuel needs, capped at 40 percent of fuel volumes and a 50/50 sharing of hedge gains and losses between customers through a monthly fuel adjustment.[181]

Stabilise the FAR

The current application of the FAR passes fuel cost changes through to customers relatively quickly. While this ensures full cost recovery, it also exposes customers to short-term price volatility.

The Minister may direct the RA to update the Schedule to the Retail Tariff Methodology General Determination to incorporate a FAR stabilisation mechanism. In response, the RA could consider one or more of the following measures:

- **Introducing a fuel cost smoothing mechanism:** The RA could set a reference fuel cost derived from a longer-term average of market fuel prices. The difference between actual fuel costs and the reference would be tracked in a regulatory deferral account: when fuel costs exceed the reference, the shortfall would accumulate and be recovered from customers over time. Similarly, when fuel costs are below the reference, a surplus would accumulate to be returned to customers through the tariff. At each tariff review, the account balance would be recovered or refunded gradually, smoothing the impact of short-term fluctuations on customers' bills.
- **Introducing risk-sharing mechanisms:** The RA could require that a portion of fuel price variation be shared between BELCO and customers, rather than passed through entirely. For example, BELCO could retain a share of cost savings when fuel costs are below a defined benchmark and absorb a share of cost increases when actual costs exceed the benchmark. This would be similar to the OPEX incentive already in place. This creates a modest incentive for managing costs and limits the exposure of customers to price shocks.
- **Adjusting the frequency of the FAR pass-through:** The RA could lengthen the period during which fuel cost adjustments are made, for example, by moving from quarterly to semi-annual or annual changes. This would reduce the frequency of tariff adjustments and provide more predictability. However, this delays cost recovery and may increase the size of future adjustments.

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[180] The RA could establish these requirements through existing provisions in the TD&R Licence and RAA:
BELCO. 2017. "Transmission, Distribution and Retail Licence". Conditions 6 and 7; RA. 2011. "Regulatory Authority Act 2011," Sections 13, 15(2), 62, and 69-73. Link.

[181] Fair Trading Commission Barbados. October 21, 2021. "Decision on the Application by the Barbados Light & Power Company Limited for Approval to Apply the Results and Costs Associated with a Fuel Hedging Programme to the Fuel Clause Adjustment," paras. 5-6 and 138-139. Approval appears to be conditional and limited to a 24-month pilot, with no publicly available information confirming whether BLPC ultimately implemented the program after receiving approval.

Comparable mechanisms are used in other jurisdictions. For example, in Hawaii, a fuel cost recovery mechanism includes a risk-sharing component. Under this mechanism, 98 percent of the fossil fuel cost variation is passed through to customers, and the remaining share is borne by the utility.[182] In practice, this means that when fuel costs exceed a defined benchmark, tariffs increase, but the utility absorbs a small portion of the increase; and when fuel costs fall below, customers benefit from lower tariffs while the utility retains a small share of the savings.

4.2.3 Reducing cross-subsidisation between customer classes

Reducing cross-subsidisation requires moving toward a more cost-reflective tariff structure, in which customers' contributions more closely align with the costs they impose on the system.

Tariff design falls within the RA's remit. Therefore, the Government should not prescribe specific tariff structures. Instead, it can support this objective by directing the RA to take appropriate action within its existing powers.

The RA has already developed a set of four tariff redesign options to improve cost-reflectivity. These options involve shifting cost recovery away from volumetric charges and toward fixed and demand-based charges, which better reflect the underlying drivers of system costs.[183]

The four options are presented below in order of increasing cost-reflectivity, with Option D matching most closely what it actually costs BELCO to serve each customer.

Option A proposes the smallest change of the four. Its main gain is transparency rather than structural cost reflectivity.[184] It splits the single variable rate into two components, generation and T&D and retail charge. For residential customers, the option replaces the existing inclining block variable charge with a non-inclining block variable charge. The fixed charges remain unchanged: residential customers continue to pay a monthly consumption-driven, tiered fixed charge; commercial customers continue to pay a monthly fixed charge; and demand customers continue to pay a monthly fixed charge and three types of demand charges per kW.

Option B uses the same fixed-charge structures as Option A but unbundles the variable rate further, into three components:[185] generation, transmission, and distribution/residual. Because the unbundling allows each component of the variable rate to be more closely aligned with the underlying costs it recovers, the share of fixed costs recovered through fixed charges is higher than under Option A.

Option C goes a step further by changing the structure of the fixed charge itself, not just the variable rate, unlike options A and B.[186] The variable rates are unbundled into the same three components as in Option B. For residential customers, the consumption-driven GFC tiers are replaced with demand-driven GFC tiers, based on each customer's peak kW draw, grouped into

[182] Hawaiian Electric Industries. 2020. "Annual Report to Shareholders," p. 18. Link

[183] RA. October 2022. "Retail Tariff Design Restructuring Report," p.19. Link

[184] RA. October 2022. "Retail Tariff Design Restructuring Report," p.7. Link

[185] RA. October 2022. "Retail Tariff Design Restructuring Report," p.11. Link

[186] RA. October 2022. "Retail Tariff Design Restructuring Report," p.13. Link

tiers that hold steady over a year, with a single fixed customer-service charge also applying. For commercial customers, a new single fixed demand charge is added on top of their existing single fixed charge. The fixed-charge structure for demand customers is unchanged. Option C allows a higher recovery of fixed costs through fixed charges than Option B, as it introduces demand charges that track grid usage. The trade-off is added complexity for BELCO's billing system and reduced bill comprehensibility for residential and commercial customers unfamiliar with demand charges.

Option D is the most cost-reflective of the four designs.[187] The variable rate uses the same three-component structure as in Options B and C (generation, transmission, and distribution/residual), and each customer class (residential, commercial, demand) has a single fixed monthly charge and one peak power charge, with each customer's bill reflecting their own metered peak demand. Because the fixed-cost contribution now scales continuously with actual peak draw, less of the fixed-cost recovery is left in the variable rates than under any other option, although any residual fixed costs not collected through the customer charge or peak power charges still pass through the variable energy charges. The trade-off is that Option D is the most complex of the four to implement and the hardest to explain to customers.

Across all four options, the demand customer class sees relatively little structural change because it already has a fixed charge and three demand charges. Most of the realignment falls on residential and commercial customers, for which the current tariff structure is furthest from cost-reflectivity.

The RA is also exploring time-varying pricing options, including time-of-use (TOU) rates, critical peak pricing, and interruptible rates.[188] The RA acknowledges that cost-based TOU is not yet economically justified, given that generation costs are relatively steady throughout the day under the current generation mix.[189] The Minister can direct the RA to reconsider TOU options when Bermuda's generation mix justifies it, for example, as renewables penetration increases and the cost of generation begins to vary more significantly across the day.

5 Licensing framework

BELCO currently holds Bermuda's only TD&R Licence, giving it the exclusive right to transmit, distribute, and retail electricity.[190] The current framework has worked well in a power system centralised around a vertically integrated power utility responsible for generating, distributing, and retailing electricity to end-users.

However, that framework can become restrictive as the sector evolves. New technologies and business models—such as EV charging and direct supply arrangements between generators and

[187] RA. October 2022. "Retail Tariff Design Restructuring Report," p.15. Link

[188] RA. October 2022. "Retail Tariff Design Restructuring Report," p.23. Link

[189] Meeting with RA. April 2026

[190] Government of Bermuda. "Electricity Act 2016," Sections 20(1)(a) and 20(2).

large customers—do not fit easily within the current licensing framework. In some cases, the existing rules create uncertainty and may prevent arrangements that could reduce overall system costs.

Against this backdrop, the Government is considering whether to allow parties other than BELCO to obtain a TD&R Licence. As Bermuda is moving forward with EV charging and exploring ways to reduce electricity costs for large users, the Government must take into account several considerations, including: whether EV charging should be treated as a retail supply of electricity; whether a single large user should be able to procure electricity from a third-party IPP; and whether general retail competition should be introduced, such that multiple retailers may sell electricity to any customer.

This section assesses the challenges with the current framework for the retail supply of electricity in the context of EV uptake and third-party supply of electricity to large users (Section 5.1) and recommends a set of measures that address these issues without opening the general retail market (Section 5.2).

5.1 Challenges under the current framework

Bermuda has set ambitious policies for supporting EV uptake. The draft NESP 2026 includes measures such as a dedicated EV tariff with TOU pricing to encourage charging during off-peak hours. It also supports other developments, such as smart charging and vehicle-to-grid technologies, advanced metering, and dual-role residential tariffs, enabling EVs to function as distributed energy resources and providing flexibility and storage capabilities.[191]

The National Electric Vehicle Charging Infrastructure Policy aims to advance the development of an island-wide charging network, ensuring the grid can integrate increased EV demand, updating building requirements to incorporate EV charging provisions, and encouraging private sector investment in public and private charging infrastructure.[192]

The draft EVolve policy goes further, proposing a staggered ban on imports of new internal combustion engine vehicles, starting with motorcycles in 2028 and running through to heavy trucks in 2040.[193] Both the draft 2026 NESP and the National Electric Vehicle Charging Infrastructure Policy recognise the need for legislative amendments to facilitate the resale of electricity for EV charging.

EV uptake has already started and is expected to grow rapidly. The draft NESP 2026 estimates that EVs could increase annual demand by 42GWh to 54GWh by 2045,[194] equivalent to roughly 10

[191] Government of Bermuda. "The National Electricity Sector Policy," p. 44. Link

[192] Government of Bermuda. "National Electric Vehicle Charging Infrastructure". Link

[193] Government of Bermuda. "EVolve Bermuda Public Engagement Document," p. 5. Link

[194] Government of Bermuda. "The National Electricity Sector Policy," p. 15. Link

percent of current demand.[195] The Government has already electrified around 60 percent of the public bus fleet and issued tenders for EV charging infrastructure at government locations.[196]

However, the current framework was not designed with third-party EV charging in mind, and effectively, prohibits the resale of electricity. Under Section 20(2) of the Electricity Act, the RA may issue only one TD&R Licence,[197] which BELCO holds through 2047. Consumers may not receive electricity from any source other than BELCO under Section 19(2)(b) of the Electricity Act.[198]

While the RA may issue other categories of licence, none of them allows third parties to retail electricity. These other licences include:

- The Bulk Generation Licence allows generation at or above 500kW for sale to the grid.[199]
- The Bulk Generation Sole Use Installation (BGSUI) Licence allows on-site generation at or above 500kW primarily for self-consumption, with limited export to the grid of up to 30 percent of total generation at any given time.[200]
- The Large-Scale Self-Supply Licence allows self-supply at or above 500kW, but requires the installation to be fully off-grid without a BELCO meter.[201] No such licence has been issued to date.
- The Innovative Licence (Section 32A, inserted by the Electricity Amendment Act 2022) provides flexibility for pilot projects but does not enable general retail supply.[202]

This means there is no clear legal basis for third-party EV charging, which could slow the rollout of EVs. Charging activity at a public station could be treated as retail electricity supply, which falls within BELCO's exclusive rights. In practice, this creates uncertainty and may lead to informal or workaround arrangements. The Government, for example, has addressed this issue for its own EV chargers by paying BELCO directly for the electricity consumed, rather than treating charging as a standalone commercial activity.[203] Similar informal arrangements exist in other jurisdictions, such as Jamaica, for example, where the utility has tolerated the resale of electricity despite formal restrictions.

Similarly, the current licensing framework also prevents large users from purchasing power directly from third-party generators,[204] even in cases where this could reduce total system costs. Section 19 of the Electricity Act defines "receiving electricity from a person other than the TD&R

[195] RA. December 2025. "Retail Tairff Review Public Report". Link

[196] Government of Bermuda. "Evolve Bermuda," p. 9. Link

[197] Government of Bermuda, "Electricity Act 2016," Section 20(2)Link

[198] Government of Bermuda, "Electricity Act 2016," Section 19(2)(b). Link

[199] Government of Bermuda. "Electricity Act 2016," Section 20. Link

[200] RA. 2025. "Bulk Generation Sole Use Installation Licence Feed-in Tariff (FiT) Methodology Preliminary Report". Link

[201] Government of Bermuda. "Electricity Act 2016," Section 20. Link

[202] Government of Bermuda. May 2023. "New Legislative Amendments Pave the Way for Energy Regulatory Sandbox". Link

[203] The Royal Gazette, "Information requested for EV charging stations". Link

[204] Government of Bermuda. "Electricity Act 2016,"Section 19. Link

Licensee" as a prohibited activity for any person,[205] and prohibits the use of the grid to transport electricity between third-parties.[206] Section 48 of the Electricity Act reinforces this by defining a PPA as an agreement "between the TD&R Licensee and a third party," not between a third party and an end-user.[207]

Together, these provisions mean that an IPP may not generate, connect to the grid, and supply power to a specific customer when generation and consumption are not on the same site. The Building Code reinforces this structure by requiring a BELCO meter and connection before a completion certificate is issued, meaning that customers are connected to BELCO by default, even if they could be supplied by a third party or self-supplied.[208]

5.2 Recommendations for the retail supply of electricity

A modernised licensing framework should give legal clarity to new market arrangements that can reduce system costs, such as third-party EV charging and direct supply to large users, while preserving the integrated structure of Bermuda's electricity sector and BELCO's central role in providing a reliable supply.

To achieve this, the Government can introduce targeted amendments to the Electricity Act that address each of these use cases separately, while ensuring robust safeguards for grid access. This section sets out two targeted reforms: clarifying the legal status of EV charging so that charging operators can legally recover their costs without requiring a TD&R Licence (Section 5.2.1) and if the Government chooses, introducing a limited licensing mechanism that allows third-party generators to supply specific large users through bilateral arrangements, subject to a public-interest test (Section 5.2.2).

5.2.1 Allow third-party EV charging

The Government can amend the Electricity Act to clarify that supplying electricity via EV charging infrastructure does not constitute retail supply. This would recognise that EV charging is a service provided to mobile users at a transient point of supply, rather than the supply of electricity to fixed premises for stationary use. The amendment would allow EV charging operators to recover the cost of electricity they purchase from BELCO without requiring a TD&R licence or undermining BELCO's TD&R Licence. It is also in line with the draft 2026 NESP, which plans for amendments to the Electricity Act where necessary "to enable the regulated resale of electricity for EV charging and to support the continued expansion of a reliable and accessible charging network".[209]

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205 Government of Bermuda. "Electricity Act 2016," Section 19. Link

206 Government of Bermuda. "Electricity Act 2016," Section 19. Link

207 Government of Bermuda. "Electricity Act 2016," Section 48. Link

208 Government of Bermuda. 2014. "Bermuda Building Code". Link

209 Government of Bermuda. April 2026. "The National Electricity Sector Policy Consultation Draft," p. 43 Link

Barbados and Hawaii offer two examples of comparable jurisdictions have updated their legal frameworks to allow third-party EV charging without opening full retail electricity competition, as described in Box 5.1.

Box 5.1: Examples of EV charging legislation

Barbados

Barbados' 2024 Electricity Supply Act introduced flexibility by allowing new types of electricity-related services to operate within defined licence structures, rather than requiring them to fit within traditional utility roles. This created a licensing category for microgrid systems that generate and supply electricity outside the main public grid.[210] Under this licensing category, a dedicated EV charging facility with its own generation or storage can be structured as a licensed microgrid.

The Act also introduced a separate licence for the commercial sale of electricity as an activity in its own right, creating a legal category under which a commercial charge point operator could be licensed.[211]

Hawaii

The State Legislature amended the definition of "public utility" in 2009 to clarify that EV charging operators are not public utilities solely because they own or operate EV charging facilities.[212] The amendment excludes any entity that "owns, controls, operates, or manages a plant or facility primarily used to charge or discharge a vehicle battery that provides power for vehicle propulsion" from the definition of public utility.[213]

As a result, businesses that operate EV charging stations can buy electricity from the grid and resell it to EV drivers without needing a utility licence or being subject to rate regulation. This has encouraged the development of a competitive market in EV charging without applying the regulatory framework used for traditional electricity suppliers.[214]

5.2.2 Allow third-party supply to large users

The Government may consider introducing a limited licensing mechanism that allows third-party generators to supply electricity to specific large users, subject to clear safeguards. This could be done by amending the Electricity Act to allow the RA to issue a licence enabling an IPP to generate, access the grid, and supply a contracted customer through a bilateral agreement.

Introducing this new licensing mechanism would also require coordinated amendments to several provisions of the Electricity Act working together. For example, Section 19 would need to be amended to allow third parties to use the grid to deliver electricity to specific customers. In addition, Sections 47 and 48 would need to be amended to ensure that power purchase

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210 Government of Barbados. 2024. "Electricity Supply Bill, 2024," Sections 2 and 4. Link

211 Barbados Parliament. September 2024 "Bill as amended," Sections 2, 9(1)(a)(vi),(vii). Link.

212 Hawaii Public Utilities Commission. 2009. "2009 Annual Report," Section 8, Transportation Energy Initiatives. Link.

213 Hawaii Revised Statute § 269-1 provides that an entity that "owns, controls, operates, or manages a plant or facility primarily used to charge or discharge a vehicle battery that provides power for vehicle propulsion" is not defined as a public utility.

U.S. Department of Energy, Alternative Fuels Data Center. Accessed May 2026. "Hawaii Laws and Incentives: Public Utility Definition." Link.

214 Capitol Hawaii. "Part I, Public Utilities, Generally," Paragraph 2 (L). Link

agreements are not strictly defined as arrangements between BELCO and generators. As they currently are, these provisions prevent IPPs from supplying electricity directly to large users.

Such licences should be granted only where the arrangement demonstrably serves the public interest. The RA should be required to assess each proposal against a defined set of criteria, including whether it reduces the overall cost of electricity for the system, avoids shifting costs onto other BELCO customers, maintains reliability and security of supply, and supports environmental objectives. Any approved arrangement should also be consistent with the IRP, so that it is integrated into long-term system planning. Where the RA is not satisfied that the criteria and requirements above are met, it would refuse the licence.

To ensure fair cost recovery, third-party generators should pay appropriate charges for use of the network and, where relevant, for access to backup capacity provided by BELCO.

This approach would allow cost-reducing arrangements in clearly defined cases, without undermining the integrated structure of Bermuda's electricity sector or BELCO's TD&R licence. Third-party supply would be permitted only as an exception, on a case-by-case basis, and only where a clear public-interest case is demonstrated. BELCO would remain the default supplier and the sole provider of general retail service.

It would also position Bermuda to accommodate emerging demand from large users seeking dedicated supply, including renewable energy, in line with global trends toward direct agreements between generators and end-users.

6 Minister's role in the power sector

High electricity prices, exposure to fuel prices, and delays in system planning have put pressure on the Government to play a more active role in shaping outcomes in the electricity sector. Bermuda's legal framework gives the Minister of Home Affairs (the Minister) several channels to influence how the electricity sector is regulated and operated, but it also places clear limits on direct political control to safeguard the RA's independence on methodologies and case-specific decisions.

Section 6.1 discusses the legal channels through which the Minister can shape the electricity sector and the limits the framework places on that influence. Section 6.2 recommends practical ways the Minister can use its existing powers more effectively to deliver on policy commitments.

6.1 Challenges under the current framework

The Minister's role in the sector operates through two sets of channels for the Minister to shape the electricity sector:

- Channels that allow the Minister to shape the RA's methodologies at a general level, so that they reflect Government policy. These are Ministerial declarations, directions, requests for technical analysis, and regulations (section 6.1.1); and

- Channels that leave the Minister with indirect influence on licences and specific matters through the RA, while limiting authority over individual licensees and case-specific decisions to the RA (section 6.1.2).

Under this framework, the Minister is responsible for setting overall policy direction for the sector, while the RA is responsible for applying that policy through independent regulatory decisions. This division is intended to protect the RA's independence, while allowing the Government to set clear priorities for the sector.

Although in many ways, this has been effective, there have also been some challenges. While the Minister has tools to influence the sector—such as policy declarations and directions—these are not always used to shape outcomes early in the process. At the same time, the Minister is limited in the ability to intervene in specific decisions once they are underway, even where there are broader concerns about affordability or system outcomes.

This section examines these challenges and identifies how the Minister's existing powers can be used more effectively to shape sector outcomes, while preserving the RA's independence.

6.1.1 Channels for the Minister to shape the RA's methodologies

The Electricity Act and Regulatory Authority Act give the Minister directive influence over the RA's methodologies upstream, before they are formally issued, through four main channels:

- Ministerial declarations that establish policies for the electricity sector (section 7(2) of the Electricity Act and section 4(2) of the Regulatory Authority Act);[215, 216]
- Ministerial directions to the RA on any matter within the Minister's authority, and designed with due regard to the purposes of the Electricity Act (sections 8(1) and 8(2) of the Electricity Act and sections 7 and 8 of the Regulatory Authority Act);[217, 218]
- Technical analyses and advice that the Minister may request from the RA where necessary for the Minister to perform his duties (Section 12 of the Electricity Act);[219] and
- Regulations establishing the general requirements regarding the means by which the RA implements the Electricity Act, Regulatory Authority Act, and approved sectoral policies, made by the Minister after conferring with the RA and consulting sectoral participants (Section 54 of the Electricity Act and Section 5 of the Regulatory Authority Act).[220, 221]

Section 9 of the Electricity Act gives the Minister substantial discretion to set policy priorities in the Ministerial directions. In formulating such directions, the Minister sets priorities and resolves trade-offs among the purposes of the Electricity Act in the way that, in the Minister's opinion, best

[215] Government of Bermuda. "Electricity Act 2016," Section 7(2). Link

[216] Government of Bermuda. "Regulatory Authority Act 2011," Section 4(2). Link

[217] Government of Bermuda. "Electricity Act 2016," Sections 8(1)-(2). Link

[218] Government of Bermuda. "Regulatory Authority Act 2011," Sections 7-8. Link

[219] Government of Bermuda. "Electricity Act 2016," Section 12. Link

[220] Government of Bermuda. "Electricity Act 2016," Section 54. Link

[221] Government of Bermuda. "Regulatory Authority Act 2011," Section 5. Link

serves the public interest (section 9(1) of the Electricity Act),[222] taking into account Government policy, the purposes of the Electricity Act, public comments, and any technical analysis given by the RA (section 9(2) of the Electricity Act).[223] For example, if affordability and increasing renewable generation are in tension, the Minister is the one who decides how to weigh them.

The RA must then act in accordance with Ministerial directions and exercise its functions within the framework of sectoral legislation, sectoral policies, and any regulations made by a Minister (sections 8(5) and 15(1) of the Electricity Act; Sections 7(1) and 15(1) of the Regulatory Authority Act).[224, 225]

However, the framework deliberately limits the Minister's reach in order to safeguard the RA's regulatory independence over methodologies and case-specific decisions. In particular:

- The RA has the power to make administrative determinations, adjudicative decisions, and rules (Section 13 of the Regulatory Authority Act),[226] including general determinations that are binding on sectoral participants (Section 15(2) of the Regulatory Authority Act).[227] General determinations are issued under Section 62 of the Regulatory Authority Act, subject to public consultation under Sections 69 to 73, but do not require Ministerial approval.[228]
- The RA is responsible for setting key methodologies, including the methodology for setting or approving retail tariffs and regulating revenues (Section 35 of the Electricity Act),[229] the feed-in tariff methodology (sSction 36 of the Electricity Act),[230] and service standard indicators and target setting for reliability, power quality, and customer service for the supply of electricity (Section 34 of the Electricity Act).[231]

6.1.2 Minister's influence over individual licensees and specific matters

The current legal framework places clear limits on the Minister's power over individual licencees such as BELCO, nor over specific matters such as determining BELCO's allowed revenue.[232] The Minister may not direct the outcome of an individual case once it is before the RA. The Minister may also not amend BELCO's TD&R Licence directly, since the Minister is not a party to the Licence, and BELCO's TD&R Licence requires BELCO to comply with Ministerial regulations and

[222] Government of Bermuda. "Electricity Act 2016," Section 9(1). Link

[223] Government of Bermuda. "Electricity Act 2016," Section 9(2). Link

[224] Government of Bermuda. "Electricity Act 2016," Sections 8(5), 15(1). Link

[225] Government of Bermuda. "Regulatory Authority Act 2011," Section 15(1). Link.

[226] Government of Bermuda. "Regulatory Authority Act 2011," Section 13. Link.

[227] Government of Bermuda. "Regulatory Authority Act 2011," Section 15(2). Link.

[228] Government of Bermuda. "Regulatory Authority Act 2011," Sections 62, 69-73. Link.

[229] Government of Bermuda. "Electricity Act 2016," Section 35. Link

[230] Government of Bermuda. "Electricity Act 2016," Section 36. Link

[231] Government of Bermuda. "Electricity Act 2016," Section 34. Link

[232] Section 8(4) of the Electricity Act prevents the Minister from directing the RA on the application of general policies to specific matters or on the specific rights or obligations of any individual licensee.

directions issued under the Electricity Act, which as explained above set only general policy and direction (Condition 6).[233]

Both the legislation and BELCO's TD&R Licence place this direct power exclusively with the RA. In particular, the RA may:

- Make administrative determinations that establish the legal rights and obligations of BELCO and other sectoral participants (Sections 13 and 15(2) of the Regulatory Authority Act);[234]
- Grant, modify, suspend, or revoke licences (including BELCO's TD&R Licence) and modify service standards, of its own motion or with the consent of the licensee (Section 29 of the Electricity Act);[235]
- Set and monitor service standards under Part 6 of the Electricity Act;[236] and
- Make emergency general determinations without public consultation where the urgency of the case requires it (Section 66 of the Regulatory Authority Act).[237]

While Section 66(2) of the Regulatory Authority Act provides emergency powers to the RA, neither the Electricity Act nor the Regulatory Authority Act gives such powers to the Minister.[238]

The Minister may still act on operational matters about individual licensees, but does so indirectly, by directing the RA to use its own powers. The Minister has used this indirect route in the past, directing the RA on how to use its own powers in response to specific events. In 2020, for example, following a series of power disruptions, the Minister directed the RA to provide urgent information on BELCO's response and the RA's assessment.[239] More recently, in 2023, the Minister issued a direction requiring the RA to take action in response to BELCO's breach of the Clean Air Act and its Licence conditions.[240]

As a result, the effectiveness of Government policy depends largely on how clearly it is reflected in the RA's methodologies and processes. Where these are not aligned with policy objectives, the Minister has limited ability to influence outcomes once decisions are underway.

6.2 Recommendations for the Minister's role in the power sector

An effective Ministerial role in the electricity sector is one that sets clear policy direction at the strategic level, shapes the methodologies the RA uses to set tariffs and standards, and applies

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233 RA. "Transmission Distribution & Retail Licence," Condition 6. Link.

234 Government of Bermuda. "Regulatory Authority Act 2011," Sections 13, 15(2). Link.

235 Government of Bermuda. "Electricity Act 2016," Section 29. Link

236 Government of Bermuda. "Electricity Act 2016," Part 6. Link

237 Government of Bermuda. "Regulatory Authority Act 2011," Section 66. Link.

238 Government of Bermuda. "Regulatory Authority Act 2011," Section 66(2). Link.

239 Government of Bermuda. December 2020. "Minister Roban – BELCO Outage". Link

240 Government of Bermuda. June 2023 "RE: DIRECTION TO THE REGULATORY AUTHORITY REGARDING BELCO EMISSIONS". Link

Ministerial powers to address system-wide risks where the public interest requires it, in a way that complements rather than substitutes for the RA's regulatory functions.

The existing legal framework already provides sufficient channels for the Minister to act in this way, in particular through Ministerial declarations under Section 7(2) of the Electricity Act and Ministerial directions under Section 8 of the Electricity Act.

This section sets out three ways the Minister can use these powers more deliberately: ensuring the RA's methodologies are aligned with policy objectives (Section 6.2.1), shaping methodologies upstream rather than seek to influence specific outcomes downstream (Section 6.2.2), and using policy directions to address system-wide risks (Section 6.2.3).

6.2.1 Ensure RA's methodologies are aligned with policy objectives

The Minister can issue the 2026 NESP as a formal Ministerial declaration under section 7(2) of the Electricity Act.[241] The declaration should explicitly cite Section 7(2) as its statutory basis, as doing so places the NESP unambiguously within the scope of Section 15(1) of the Regulatory Authority Act, which requires the RA to perform its functions in accordance with policies made by a Minister.

In practice, this would require the RA to reflect policy objectives, such as affordability, reliability, and renewable integration, when setting tariff methodologies, planning processes, and service standards.

6.2.2 Shape methodologies upstream, not outcomes downstream

The Minister can combine the declaration described above with a Ministerial direction requiring the RA to act in accordance with the 2026 NESP objectives. The declaration and the direction perform different legal functions: The declaration under Section 7(2) of the Electricity Act establishes Government policy for the sector,[242] while the direction is a formal instruction with which the RA must act in accordance under Section 8(5).[243]

For example, the direction could require the RA, in setting its service standards and tariff methodologies, to give effect to the NESP's objectives on affordability, reliability, and renewable integration. The direction would need to remain within the limits of Section 8(4) of the Electricity Act, which prevents the Minister from directing the RA on how to apply policy to specific matters or individual licensees.

As part of the Ministerial direction, the Minister could request the RA's advice on the best way to achieve the NESP objectives under Section 12 of the Electricity Act.[244] This would help the Minister write a direction that the RA can actually act on, as the Minister would receive the RA's analytical inputs on what is feasible, the trade-offs between policy objectives, and realistic time horizons. It

241 Government of Bermuda. "Electricity Act 2016," Section 7(2). Link

242 Government of Bermuda. "Electricity Act 2016," Section 7(2). Link

243 Government of Bermuda. "Electricity Act 2016," Section 8(5). Link

244 Government of Bermuda. "Electricity Act 2016," Section 12. Link

would also ease the RA's implementation of the direction, as a direction informed by the RA's own advice would leave the RA and other sectoral participants with little ground to contest it.

The direction could also require the RA to consult the Minister on draft methodologies and general determinations before they are issued. Upstream consultations would ensure that RA's methodologies and determinations are aligned with NESP objectives from the outset, reducing the scope for disputes after they are issued.

6.2.3 Use policy directions to address critical system risks

Where system-wide risks persist—such as planning delays, exposure to fuel price volatility, or high electricity costs—the Minister may use Section 8 directions to require the RA to review whether existing licences and service standards remain fit for purpose, whether enforcement tools are being used effectively, and whether regulatory frameworks continue to serve the public interest.

The Minister may also use directions to require the RA to address specific operational risks, while staying within the limits of Section 8(4) of the Electricity Act. For example, the Minister may direct the RA to investigate and respond to operational issues affecting reliability or public safety, as the Minister did in 2020 and in 2023 in response to BELCO's breach of the Clean Air Act 1991. The Minister may also direct the RA to consider whether BELCO's licence and service standards should be modified under Section 29 of the Electricity Act to address any gaps that contributed to those operational issues.[245]

[245] Government of Bermuda. "Electricity Act 2016," Section 29. Link

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