REGULATORY AUTHORITY OF BERMUDA

RETAIL TARIFF DESIGN RESTRUCTURING REPORT

Considerations for an Updated Approach to Calculating Electricity Bills

Request for Public Comment
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TABLE OF CONTENTS

1. INTRODUCTION

As an independent regulatory body, the Regulatory Authority (RA) has a mandate which includes:

- Promoting fair business practices
- Protecting user and industry stakeholders, and
- Encouraging integrity in the markets it regulates.

This public report seeks primarily to re-evaluate how electricity bills are calculated to ensure alignment with these mandates. We seek to ensure that among the many legitimate ways utilities could use to fairly calculate customer bills, the approach adopted stays current with what best suits Bermuda. The RA's major considerations are fairness in billing, and better ways for monies spent to service each customer being represented on their bills.

Two other considerations are a billing approach that would keep bills almost identical every month and rates encouraging people to use electricity at different times. This report seeks feedback from the public on the discussed material.

2. BACKGROUND

Observing the evolving electricity sector has prompted the RA to consider if better ways monies spent to service each customer can be represented on their electricity bills. While the current approach is fairly easy to implement and generally well understood by customers, the interest of fairness may warrant billing changes. Consider for example that every customer has grid access – a connection to the equipment that generates and delivers power to them. Fairness would see customers pay their portion of the associated grid equipment costs. The RA sees fairness in payment for access to power grid equipment as the major issue under the current approach to calculating electricity bills.

Bermuda's energy consumption has fallen significantly since 2008. While the current billing approach was suited for past consumption levels, under these circumstances, calculation methods cause some customers to pay significantly more for power grid equipment and access than others. Further, where customers generate some energy themselves (e.g. use solar systems) the current approach to calculating bills often causes underpayment for grid access, thereby raising grid access charges to other customers. With falling consumption and increasing self-generation putting fairness at risk under the current billing approach, the RA seeks to move closer to a billing approach where specific user's bills reflect monies spent to serve them.

The RA is mandated to promote fairness among stakeholders, and this includes fairness taking effect in the bill calculation methods it approves. With this said, the RA is mindful that addressing any unfairness in billing is not itself without consequences. Any changes will likely increase billing implementation complexity for the utility and reduce customers' understanding of their bills. Thus, in considering moves toward improved fairness in billing, the RA also seeks to balance these against likely consequences. Balancing somewhat conflicting priorities - fairness, transparency & understandability to customers and ease to implementation by the utility – will likely prove challenging. Other considerations include designing approaches to calculating bills that minimize (not eliminate) price shocks where possible. Finally, the RA must consider ongoing market fluctuations users face and seek an approach to bill calculation that protects customers as much as possible from fluctuations, without overly reducing transparency and reasonably timely prices for decision making.

Within this context, this report covers the following options to consider:

- Updating bill calculations for all customers
- Updating bill calculation for customers with distributed generation
- Time varying pricing
- Protecting eligible customers
- Levelised (constant) monthly bills

The public understanding how bills are calculated is important, hence this public report seeks to provide accessible, non-technical, plain, and unambiguous explanations regarding the different considerations.

The public can comment on these considerations using the “Feedback Form” attached to this report, which will help inform the RA to make decisions on new ways to calculate bills. The aim is to begin implementing changes as soon as 1st January 2023.

3. OVERVIEW: CURRENT APPROACH TO CALCULATING BILLS

The RA is using this public report and comment process to explore several areas of potential improvement in the current way in which bills are calculated. As the introduction indicated, the RA is mandated to promote fairness. Fairness principles guide the RA's efforts to ensure customer charges reflect the cost to serve them. Practicality means this should be done to the furthest extent possible, without excessive complexity (for the utility) or creating bills customers find confusing. The major issue the RA sees with current calculation approach is that for a significant number of customers it produces charges that diverge significantly from the cost to serve them.

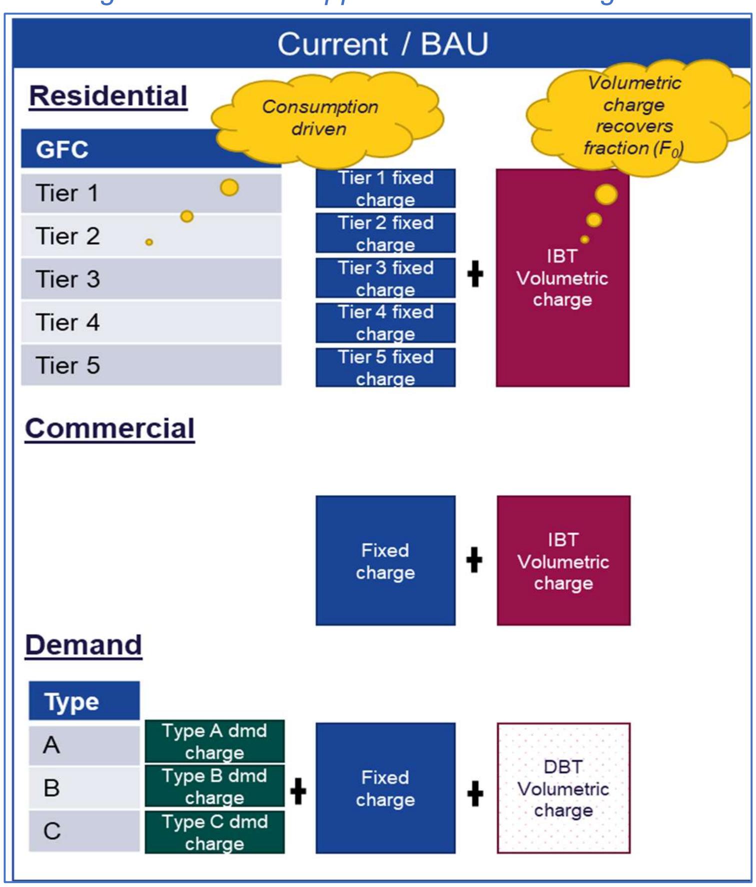
For context, the Electricity Act 2016 mandates utility rates cover all prudent costs to serve customers. These can be categorized as either fixed (largely equipment and its management) or variable (largely production related).

Fixed customer charges ideally recover all costs incurred on customers' behalf unrelated to their consumption levels. It is the cost of grid connections, all generation and power delivery equipment, plus managing it, spread fairly across customers.

Variable charges ideally recover costs which vary with electricity consumption levels. It is mainly the cost of materials, supplies and labour that varies with the amount of electricity produced. Adding their fixed and variable charges equates to a customer's total bill.

Figure 1 below highlights Bermuda's current approach to calculating bills.

Figure 1. Current Approach to Calculating Bills



All customer classes have fixed charges ($/month regardless of energy consumption). Residential customers pay fixed charges through Graduated Facilities Charges (GFC). Their fixed charges increase as their average energy consumption (kWh per day) increases, across 5 consumption tiers.

Commercial and demand customers also have a fixed charge ($/month regardless of energy consumption). Very large customers[1] pay an additional fixed charge derived from the peak power they draw from the system[2]. These customers are in 3 subcategories (A, B, C).

Overall, it is important to recognize the current way in which bills are calculated charges customers only a minor portion of actual fixed costs to serve them. The calculation shifts the majority of actual fixed costs into variable, energy consumption charges.

The current approach used to calculate each residential and commercial user's energy consumption charges sees customers pay progressively higher rates for increased electricity consumption3. Conversely, the approach for very large customers charges progressively lower rates for increased electricity consumption4.

The current bill calculation approach for all customer classes bundles distinct services - Generation, Transmission and Distribution - together into only one variable/energy charge.

The RA is mindful that variable costs the utility undertakes to serve customers is significantly lower than what is reflected on bills. Conversely, fixed costs the utility undertakes to serve customers is significantly higher than what is reflected on bills. When all bills are added up the utility only receives the correct total. However, under the current approach to calculating bills the mismatch between fixed and variable proportions means certain customers pay significantly more than the total cost to serve them. Conversely, some customers are billed significantly less than the cost to serve them.

Despite these unintended results, the RA emphasises there is nothing unusual about the current approach to billing. Regulators world-wide have for decades approved utilities charging for energy at higher than actual costs, offset by fixed charges levied at lower than actual costs, such that the resulting bill totals the cost to serve them. This arrangement was deemed to lend greater control to customers – they can take some action to lower energy consumption. Further, the approach to calculating bills is designed and monitored to ensure that the utility does not receive a penny more than it is owed. While the arrangement worked well for decades, the major changes Bermuda has undergone since 2008 sees this arrangement causing an unintended cost shift between certain customers. Evaluating the fairness of this cost shift has prompted the RA to reconsider the arrangement.

Three specific local changes are causing cost shifting issues. First, Bermuda's energy consumption has declined annually since 2008. Under the current approach to calculating bills, declining consumption reduces monies paid toward power grid equipment and its management – long term equipment investments now serving a smaller population. Adjusting for this shortfall has

[1] "Demand" class
[2] $ per kW
[3] Inclining Block Tariffs (IBT)
[4] Declining Block Tariff (DBT)

required raising energy charges higher than they otherwise would be – just to stay level with due fixed costs.

Second, there are customers that have lowered their consumption more than most through energy efficiency upgrades, downsizing homes etc. The current approach to calculating bills will understate the costs the utility has undertaken for their power grid access. These costs are collected from higher energy consuming customers.

Lastly, there are hundreds of households partly self-generating, mainly with solar systems. The current approach to calculating bills fails to collect the fixed fees that would otherwise be embedded in their variable charges, which in many cases can be zero with solar systems. As with efficient users, these costs get shifted to customers who do not have self-generation systems.

The current approach to calculating bills under these circumstances is causing an increasing gap between actual costs to serve customers and their bills. It is the major focal point of the solutions this report will now explore.

4. UPDATING APPROACH TO CALCULATING ALL CUSTOMER BILLS

The current approach to bill calculation creates bills that are relatively simple for the utility to generate (when compared with other jurisdictions) and for customers to understand. However, this simplicity shifts costs and does not make cost-shifting transparent to all. Given the potential unfairness issues highlighted above, and the overall public interest, four alternatives to the current way in which bills are calculated are being considered for implementation, beginning in 2023. These are presented below by increasing degree of complexity, with respect to the utility's implementation and customer's likely understanding of bills.

A more minor issue each option addresses is that base rates currently bundle costs associated with 3 distinct services (electricity generation, transmission, and distribution) in to one charge. The RA is considering if showing these charges separately on bills will assist customers better grasp the costs their usage imposes on the system. Greater detail on bills must be weighed against the additional back-office complexity and risk to lowering customer comprehension of their bills.

4.1. Option A

The first option explored, Option A, is shown in Figure 2 and summarised in Table 1, alongside the current way in which bills are currently calculated.

Key features of Option A include:

- Removing residential customers' higher rates for progressively increased electricity consumption. In Option A this calculation approach would be kept for commercial customers (since it is used to separate small commercial customers from larger commercial customers). The approach to calculating very large (demand) customers' energy charges would remain unchanged.

- Variable charges would be separated into 1. Generation and 2. Transmission, Distribution and Retail (TD&R) for all customer classes. This moves toward improved transparency and allowing users to better relate billed charges with costs to serve them.

- Fixed charges would remain unchanged across all customer classes.

- Option A would step toward fixed costs to serve customers being better reflected on their bills but only partly so. However, because total bill impacts may vary significantly across customers, the updated bill calculation method will need careful consideration.

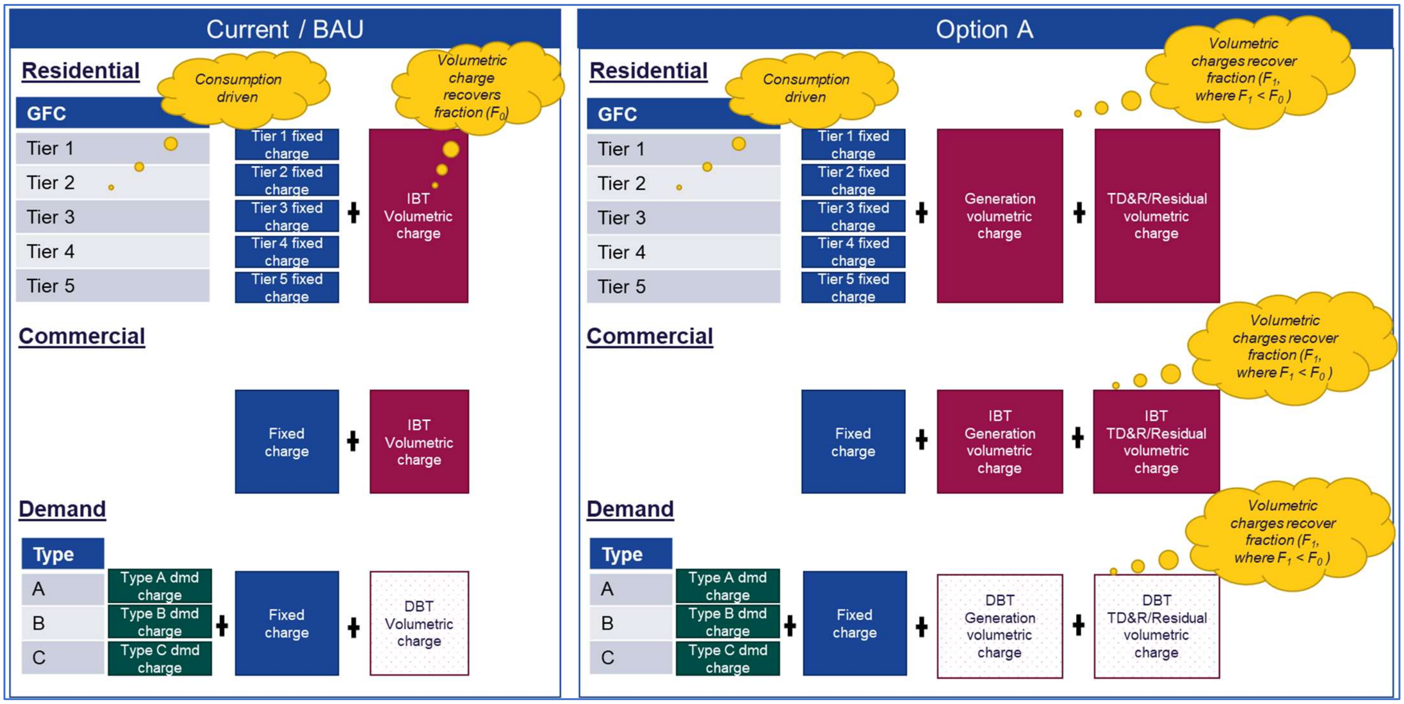
The key changes considered under Option A are summarised in Table 1, below, in comparison with the current approach to calculating bills.

Table 1. Summary of Updated Bill Calculation Approach - Option A

	Current Approach	Option A
Residential		
Fixed charges ($/month)	Consumption-driven GFC tiers	Consumption-driven GFC tiers
Variable/Energy charges (c/kWh)	1 IBT charge	2 non-IBT charges: Generation and TD&R/Residual
Demand charges ($/kW)	None	None
Fixed Cost in Variable charges	Status Quo	Incrementally lower than status quo
Commercial		
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges (c/kWh)	1 IBT charge	2 IBT charges: Generation and TD&R/Residual
Demand charges ($/kW)	None	None
Fixed Cost in Variable charges	Status Quo	Incrementally lower than status quo
Demand		
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges ($/kWh)	1 DBT charge	2 DBT charges: Generation and TD&R/Residual
Demand charges ($/kW)	Three types of demand charges	Three types of demand charges
Fixed Cost in Variable charges	Status Quo	Incrementally lower than status quo

Option A is well-suited to transition towards further cost reflectivity in electricity tariffs for Bermuda. The revised approach to calculating bills would retain many similarities to the current approach to calculating bills while being more transparent. Gradual changes would allow customers time to adjust to the revised approach, although offset by the impact on other users whose bills would otherwise be lower.

Figure 2. Updated Bill Calculation Approach for Option A



4.2. Option B

Option B represents an alternative approach to calculating bills. Displayed in Figure 3 and summarised in Table 2, it builds on Option A.

Key features of Option B include:

- Going past the separated variable energy charges in Option A (Generation and TD&R/Residual), bills will separately list generation, transmission, and distribution/residual[5] services according to costs each customer places on the system. Continuing to calculate these items-based energy usage ensures rate continuity while stepping closer toward the fixed costs to serve customers being better reflected on their bills. However, because total bill impacts may vary significantly across customers, the updated bill calculation method will need careful consideration.

- Further separating variable rates will enhance transparency and should help understanding of electricity rates and their relationship to costs.

- Similar to Option A, variable charges would be lower than current calculations dictate with fixed charges moved closer to the actual costs customers impose on the system.

- Residential customers Graduated Facilities Charges (GFC) and commercial and demand customers fixed charges would continue to be calculated in the same way.

The key changes considered under Option B are summarised in Table 2, below, in comparison with the current approach to calculating rates.

Table 2. Summary of Updated Bill Calculation Approach - Option B

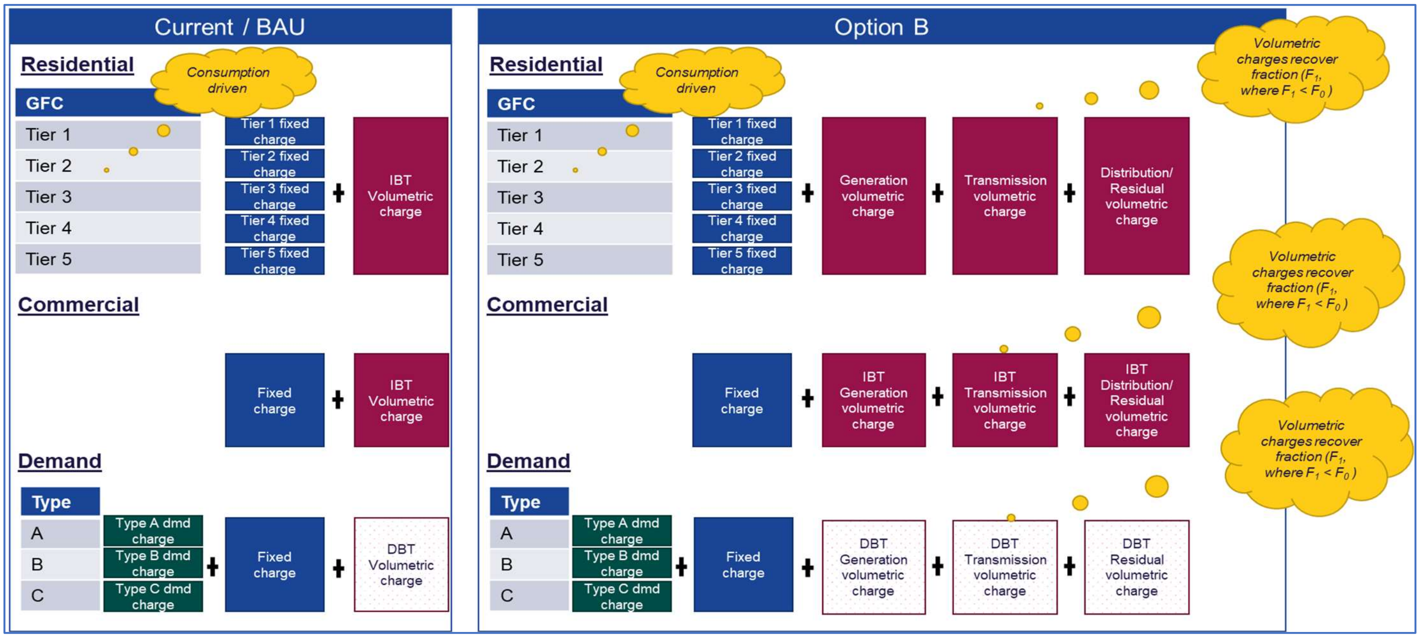
	Current Approach	Option B
Residential		
Fixed charges ($/month)	Consumption-driven GFC tiers	Consumption-driven GFC tiers
Variable/Energy charges (c/kWh)	1 IBT charge	3 non-IBT charges: Transmission, generation, and distribution/residual
Demand charges ($/kW)	None	None
Fixed Cost in Variable charges	Status Quo	Lower than option A
Commercial		

[5] Commercial and residential customers would have volumetric charges for generation, transmission, and distribution components, with the distribution charge also incorporating residual costs not recovered from other rates. Demand customers are fed from the transmission system hence only would not have a distribution charge but otherwise would see the same billing subcomponents.

	Current Approach	Option B
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges (c/kWh)	1 IBT charge	3 IBT charges: Transmission, generation, and distribution/ residual
Demand charges ($/kW)	None	None
Fixed Cost in Variable charges	Status Quo	Lower than option A
Demand		
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges (c/kWh)	1 DBT charge	3 DBT charges: Transmission, generation, and residual
Demand charges ($/kW)	Three types of demand charges	Three types of demand charges
Fixed Cost in Variable charges	Status Quo	Lower than option A

Segregating variable energy charges into transmission, generation, and distribution/residual charges in this alternative would provide further cost reflectivity and transparency to users. The figure below illustrates the approach to calculating rates with Option B.

Figure 3. Updated Bill Calculation Approach for Option B



4.3. Option C

The third alternative is Option C, presented in Figure 4 and summarised in Table 3. Going beyond Option B, it increases alignment between costs customer activity imposes on the utility and charges in their bills.

Key features of Option C include:

- Maintaining Option B's unbundled transmission, generation, and distribution/residual[6] variable/energy charges

- Changing the residential facilities charges (GFC) from energy usage based (per kWh) to peak power (per kW) based. The existing residential facilities charge seeks to recover some fixed costs based on energy usage. However, the using varying energy usage does not align with actual fixed costs to serve customers. This revision will measure peak power each customer draws from the grid and assign a fixed monthly fee[7] proportionate to it. In this way, all customers pay a fairer share for power grid equipment and its management. Peak power tiers will keep the monthly fee stable across a one-year period. The RA is mindful that despite this step better aligning costs customers create for the utility and their bills, it's a more complex billing approach and risks confusion among customers. These charges already exist among very large customers and even they can sometimes misunderstand them. Further, measuring and tracking each customer's peak demand and

[6] Commercial and residential customers would have volumetric charges for generation, transmission, and distribution components, with the distribution charge also incorporating residual costs not recovered from other rates. Demand customers would have a generation, transmission, and a residual volumetric charge, where the residual charge would recover the remaining costs not recovered from other rates.

[7] Demand charge per kW

billing accordingly adds complexity to the utility's back-office functions. It would require reconfiguring the billing system, noting such approaches are common in other jurisdictions.

- An identical peak power usage charge would be introduced in the commercial class with the same pros and cons to be considered.

- Beyond Options A and B, Option C advances billing charges being closer to costs customers cause on the sys. . It moves further from fixed charges being recovered through variable ones and thus is fairer to all customers. Even though reduced, bills under Option C still charge for some fixed costs through variable charges. What is unrecovered in the facilities and peak power charges would remain in the variable energy charges. Like Option A and B, different customers could see significantly different total bill impacts with this change and this needs careful study.

- Lastly, this alternative would introduce a singular fixed monthly customer charge in the residential customer class derived from customer service-related costs. This adds transparency for customers to see how much they pay for customer service. Even though total bills would remain unchanged, like the unbundled billing for items above, it risks adding confusion to some customers.

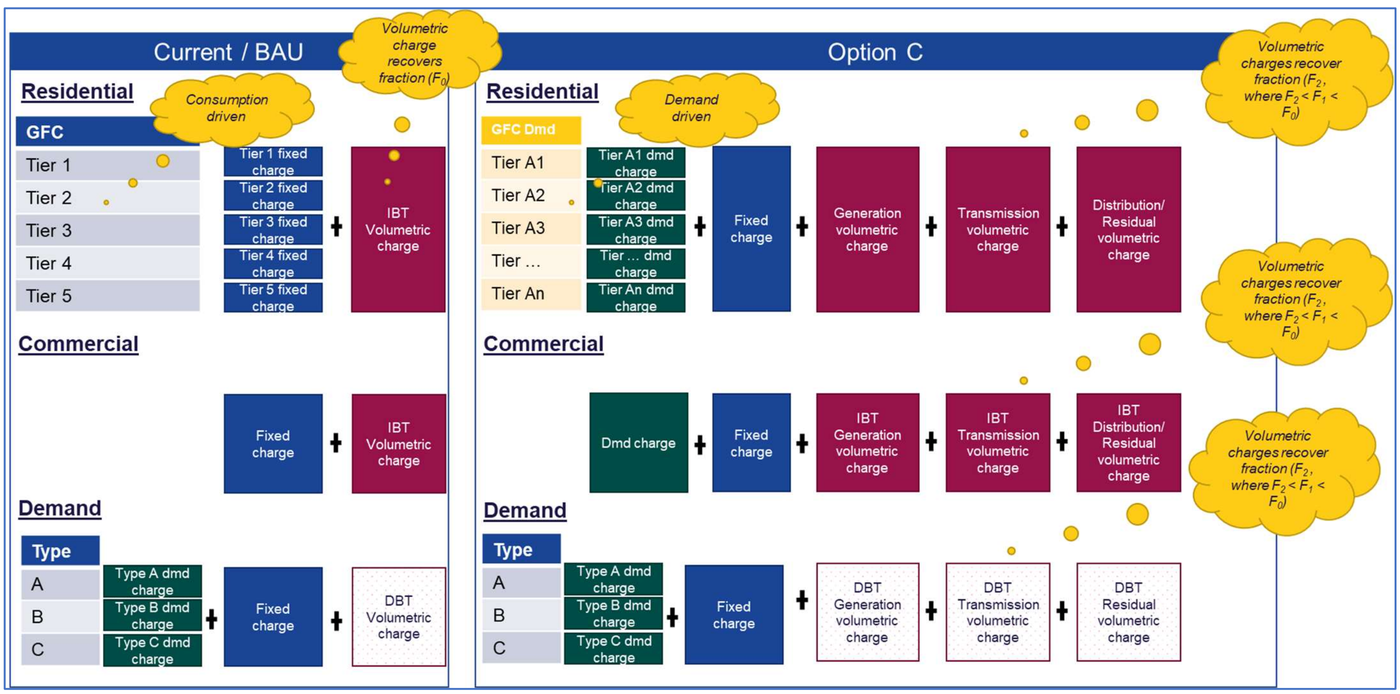
The key changes considered under Option C are summarised in Table 3, below, in comparison with the current approach to calculating rates.

Table 3. Summary of Updated Bill Calculation Approach - Option C

	Current Approach	**Option C**
Residential		
Fixed charges ($/month)	Consumption-driven GFC tiers	Single fixed charge
Variable/Energy charges (c/kWh)	1 IBT charge	3 non-IBT charges: Transmission, generation, and distribution/residual
Demand charges ($/kW)	None	Demand-driven GFC tiers
Fixed Cost in Variable charges	Status Quo	Lower than option B
Commercial		
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges (c/kWh)	1 IBT charge	3 IBT charges: Transmission, generation, and distribution/residual
Demand charges ($/kW)	None	Single demand charge

	Current Approach	Option C
Fixed Cost in Variable charges	Status Quo	Lower than option B
Demand		
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges (c/kWh)	1 DBT charge	3 DBT charges: Transmission, generation, and residual
Demand charges ($/kW)	Three types of demand charges	Three types of demand charges
Fixed Cost in Variable charges	Status Quo	Lower than option B

Figure 4. Updated Bill Calculation Approach for Option C



4.4. Option D

Option D, the final option presented builds on Option C and is displayed in Figure 5 and summarised in Table 4. Option D's key features include:

- Maintaining the unbundled generation, transmission, and distribution/residual[8] variable energy charges from Option B to Option C, and Option C's fixed monthly customer charge.

- Superseding the residential and commercial peak power tiers from Option C with a single peak power charge[9] within each customer class (residential, commercial, demand). Each customer class would have one rate designed to match the costs it imposes on the system. The peak power each customer within the customer class draws from the system[10] would be measured on their meter and factor into the calculation of their bill accordingly.

- Beyond Options A-C, Option D advances billing charges being even closer to costs customers cause on the system. It moves further from fixed charges being recovered through variable ones and thus is fairer to all customers. Even though reduced, bills under Option D may still charge for some fixed costs through variable charges. What is unrecovered in the facilities and peak power charges would remain in the variable energy charges. Like Option A-C, different customers could see significantly different total bill impacts with this change and this needs careful study.

The key changes considered under Option D are summarised in Table 4, below, in comparison with the current approach to calculating rates.

Table 4. Summary of Updated Bill Calculation Approach – Option D

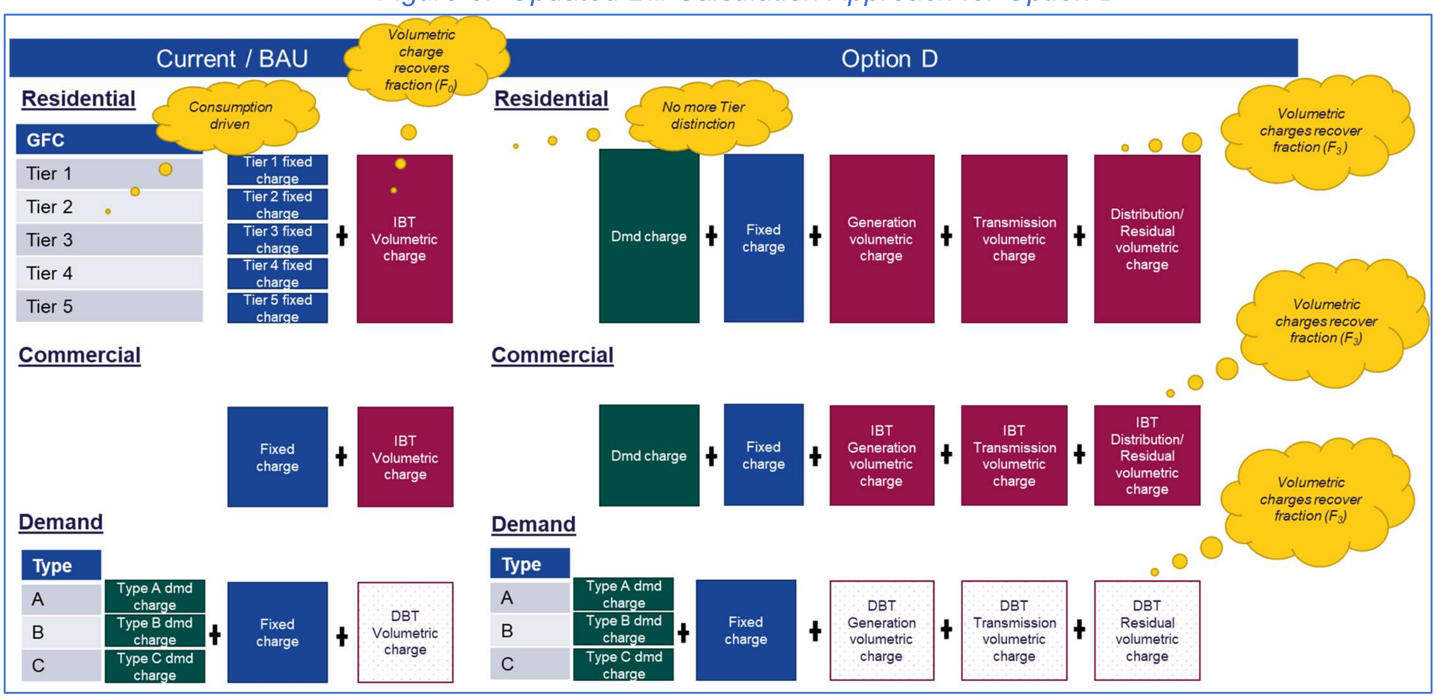
	Current Approach	Option D
Residential		
Fixed charges ($/month)	Consumption-driven GFC tiers	Single fixed charge
Variable/Energy charges (c/kWh)	1 IBT charge	3 non-IBT charges: Transmission, generation, and distribution/residual
Demand charges ($/kW)	None	Single demand charge
Fixed Cost in Variable charges	Status Quo	Lower than option C
Commercial		
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges (c/kWh)	1 IBT charge	3 IBT charges: Transmission, generation, and distribution/residual

[8] Commercial and residential customers would have volumetric charges for generation, transmission, and distribution components, with the distribution charge also incorporating residual costs not recovered from other rates. Demand customers would have a generation, transmission, and a residual volumetric charge, where the residual charge would recover the remaining costs not recovered from other rates.
[9] $ per kW
[10] Non-coincident peak demand

	Current Approach	Option D
Demand charges ($/kW)	None	Single demand charge
Fixed Cost in Variable charges	Status Quo	Lower than option C
Demand		
Fixed charges ($/month)	Single fixed charge	Single fixed charge
Variable/Energy charges (c/kWh)	1 DBT charge	3 DBT charges: Transmission, generation, and residual
Demand charges ($/kW)	Three types of demand charges	Three types of demand charges
Fixed Cost in Variable charges	Status Quo	Lower than option C

If implemented, the proposed non-tiered peak power charge would lead to more alignment between costs customers impose on the system and their specific bills. Future approaches to calculating rates can build on Option D and can introduce a further shift away from using variable rates to recover the utility's fixed charges. Figure 5 below illustrates Option D.

Figure 5. Updated Bill Calculation Approach for Option D



4.5. Summary

These 4 alternatives progressively increase the alignment between costs customers impose on the system and their actual bills. It hence increases fairness in how bills are calculated, minimizes unintended cost shifting, and provides customers with clear and accurate indications of costs the utility undertakes due to their activity. Progressively increasing fairness in billing is traded off against each iteration increasing billing data & system implementation complexity plus risking reduced customer comprehension. The options discussed above are summarised in Table 5 below.

	Current Rate structure	Option A	Option B	Option C	Option D
Residential					
Fixed charges ($/month)	Consumption-driven GFC tiers	Consumption-driven GFC tiers	Consumption-driven GFC tiers	Single fixed charge	Single fixed charge
Variable/energy charges (c/kWh)	1 IBT charge	2 non-IBT charges: Generation and TD&R/Residual	3 non-IBT charges: Transmission, generation, and distribution/residual	3 non-IBT charges: Transmission, generation, and distribution/residual	3 non-IBT charges: Transmission, generation, and distribution/residual
Demand charges ($/kW)	None	None	None	Demand-driven GFC tiers	Single demand charge
Fixed Costs in variable charges	Status Quo	Lower than status quo	Lower than A	Lower than B	Lower than C
Commercial					
Fixed charges ($/month)	Single fixed charge	Single fixed charge	Single fixed charge	Single fixed charge	Single fixed charge
Variable/energy charges (c/kWh)	1 IBT charge	2 IBT charges: Generation and TD&R/Residual	3 IBT charges: Transmission, generation, and distribution/residual	3 IBT charges: Transmission, generation, and distribution/residual	3 IBT charges: Transmission, generation, and distribution/residual
Demand charges ($/kW)	None	None	None	Single demand charge	Single demand charge
Fixed Costs in variable charges	Status Quo	Lower than status quo	Lower than A	Lower than B	Lower than C
Demand					
Fixed charges ($/month)	Single fixed charge	Single fixed charge	Single fixed charge	Single fixed charge	Single fixed charge
Variable/energy charges (c/kWh)	1 DBT charge	2 DBT charges: Generation and TD&R/Residual	3 DBT charges: Transmission, generation, and residual	3 DBT charges: Transmission, generation, and residual	3 DBT charges: Transmission, generation, and residual
Demand charges ($/kW)	Three types of demand charges	Three types of demand charges	Three types of demand charges	Three types of demand charges	Three types of demand charges
Fixed Costs in variable charges	Status Quo	Lower than status quo	Lower than A	Lower than B	Lower than C

Table 5. Summary of Rate structure Options (A-D)

Assessing all options considered requires noting their benefits and weaknesses. These are summarised in Table 6 below. Option A's benefits include less complexity than the others and similarity to the current approach to calculating bills. It offers continuity in bills with gradual changes toward customer costs being fully reflected on their bills. Option B separates currently bundled services. Options C and D adding peak power derived charges in allows rates to correlate more closely with service costs derived from measured system usage.

Table 6. Summary of Pros and Cons for Different Approaches to Calculating Bills

	Pros	Cons
Current Approach to Calculating Bills	✓ Rate continuity ✓ Relatively simple ✓ Public understanding	– Lack of cost reflectivity – Utility is susceptible to changes is consumption – IBT and GFC tiers not necessarily fit for purpose – The majority of billed charges come from variable charges
Option A	✓ Less complex than other options ✓ Similar to current approach – rate continuity ✓ Increased cost reflectivity and transparency ✓ Eliminates unnecessary IBT for residential ✓ More charges from fixed than variable charges compared to current approach ✓ Well-suited transition to more cost reflectivity	– GFCs are retained for residential class but have no cost causation – Still not fully cost reflective – Requires public engagement to support customers in understanding bills
Option B	✓ Further separation of bundled services than Option A ✓ More cost reflectivity and transparency than Option A	– GFCs are retained for residential class but have no cost causation – Still not fully cost reflective – Requires public engagement to support customers in understanding bills
Option C	✓ GFC demand tiers are more cost reflective than current GFC ✓ Single fixed charge eliminates consumption driven GFC tiers ✓ Helps improve cost reflectivity through demand charges ✓ More revenue from fixed charges – more cost reflective	– Still not fully cost reflective – Requires more public engagement to support customers in understanding bills – Can be quite complex for users to understand and for the utility to implement (in particular due to the demand charges)

	Pros	Cons
Option D	✓ Most cost reflective option ✓ Non-tiered demand charge for residential using meter data increases cost reflectivity ✓ More representative of cost-of-service study ✓ More revenue from fixed charges rather than variable ✓ Can build on the option to keep increasing transparency and cost reflectivity	– Most complex for users to understand and for the utility to implement (in particular due to the demand charges) – Requires the most public engagement to support customers in understanding bills

5. UPDATING APPROACH TO CALCULATING BILLS FOR CUSTOMERS WITH DISTRIBUTED GENERATION

The RA recognizes the trade-off Options A through D above represent. A graduated approach to fairness will ease the transition for the utility and customers, but it also lengthens the time required to address known fairness issues with how bills are calculated. An alternative approach to partly accelerate addressing the growing disconnect between costs customers impose on the system and how their bills are calculated might be to address these first among customers with Distributed generation (DG). Changes would be simpler to implement and at first only affect one customer type (across various classes). It is arguable that customers who partly self-generate electricity are generally more attentive to the industry's fundamental principles, mandates, legislation, and rules. This may allow moving toward fairness in billing calculation methods faster than with the broader user base.

DG is defined in the Electricity Act as "generation using a system with an installed capacity below the licence threshold," which is currently set at 500 kW. These generators can currently receive a Feed-in Tariff (FiT) under Bermuda's regulation, which pays generators for the excess electricity sold to the grid. Currently, the maximum rate that can be provided represents the avoided generation cost and associated economic benefits. The costs of FiT payments are currently recovered through base rates applied to all users. However, as DG levels increase, it is important to ensure that associated FiT payments do not create a disproportionate cost burden onto non-DG customers. This occurs under current approach to calculating bills, with reduced variable charges shifting fixed cost to non-DG customers as detailed above.

DG customers are automatically placed in GFC Tier 3, irrespective of their consumption. It is important to note the GFC was designed to on average approximate meter service and customer service fixed charges only. It was not designed recover generation, transmission, or distribution costs. Therefore, reduced energy use from the grid avoids paying for grid equipment <u>that is accessible and used</u> when self-generation DG is not meeting energy needs. Toward fairness and transparency, the RA sees this as needing re-evaluation.

The solution may be an approach to calculating bills that reflects utility costs to serve DG customers. This will not address other cost-shifting matters in non-DG customers and modification to the approach to calculating bills for rest the customer base could be considered in parallel[11].

Finally, the RA notes DG customers can impose additional technical grid demand issues which only amplify the cost recovery problems detailed above. DG assets are intermittent and risk causing sudden and unexpected demand from the grid if their system does not generate the required electricity at a moment's notice (e.g. cloud cover, maintenance, system failure etc.). Such events could result in further additional costs to the utility caused by these customers. Under the current approach to billing, non-DG customers would pay more due to these added costs.

6. TIME VARYING PRICING

This section explores different types of time varying pricing and the appropriateness for Bermuda. Several jurisdictions around the world have time varying pricing in place to help provide signals to users on the best times to consume electricity and help alleviate stress on the system. The section discusses traditional Time-of-Use pricing, Critical Peak Pricing, and Interruptible Rates.

6.1. Traditional Time-of-Use Pricing

Time-of-Use (TOU) pricing is when electricity prices vary during the day. Cost-based TOU pricing is when electricity prices fluctuate to reflect electricity system operating cost variations throughout the day. Peaking plants, operating during the highest electricity demand periods, have larger variable operating costs than baseload generation. Additionally, system costs can be reduced when demand fluctuations throughout the day are reduced. Generally, daily cost fluctuations increase with more renewables on the system. These technologies have very low marginal costs, and therefore, when they set the electricity price, they set it very low.

TOU pricing or setting different electricity prices during separate times of the day, can be used to send signals to customers on when to consume electricity. The signal disincentivises electricity use during high demand periods, when the electricity prices are higher, and encourages consumption during lower demand, equivalent to lower price periods. If users can and do react to the price differentials, then it can help alleviate system stress. The granularity of the TOU pricing can shift from hourly price differentiation to weekday and weekend, to seasonal patterns.

TOU pricing is not presently used in Bermuda but is common is other jurisdictions. To be effective in this goal, the system must be simple to understand by the user so the user can actually react to the price signals, change their consumption behaviour, and provide a large enough price difference to act as an incentive.

With the current system, introducing traditional cost-based TOU pricing in Bermuda is not expected to create a large enough price differentiation to elicit a response from users. The current lack of differentiation is partly due to a lack of renewable electricity generation which has low operating costs, leading to a smaller difference between baseload and peaking plants. Additionally, Bermuda's electricity generation mix is composed of similar technologies with similar operating costs, which does not lead to big price differentiation throughout the day.

[11] Adjustments to non-DG customers could be considered separately and perhaps made more gradually

Even though the cost-based TOU pricing is not currently justified in Bermuda, due to limited variations in costs and prices, it could be a more attractive option in the future. Bermuda expects to deploy more renewable energy technologies in the future to meet decarbonisation plans, which can lead to a wider variation in variable costs and prices throughout the day and year, which could then make for a stronger business case for introducing such rates in Bermuda. Therefore, it will be interesting to investigate the applicability of such rates in the future.

Another consideration is to explore non-cost-based Time-of-Use pricing. Non-cost-based TOU is when the electricity varies across the day, season, or year, but not in relation to costs. Instead, there could be a set differential or multiplier to determine the peak costs, in relation to the non-peak costs and send appropriate signals. However, issues could arise with the methodology as to elicit a response, this would mean that the prices would need to be higher than costs (as seen before relying on costs would not be strong enough send signals). This could then lead to a reduction in beneficial consumption and cause more harm to users in particular to those that cannot shift their consumption behaviour.

6.2. Critical Peak Pricing

Critical Peak Pricing (CPP) is a form of Time-of-Use (TOU) pricing which targets only certain hours in the year when the cost of energy is high because there is a potential for unserved load or high-cost units must run. This mechanism can help mitigate concerns over potentially low reserve margins during some periods of the year.

Instead of prices varying during the day, a small number of periods a year, when there is increased strain on network operation, can be designated as Critical Peak Days/Periods. During these days/periods of time, the utility could call for load reduction by increasing the electricity prices for a certain period of time.

These periods would have a larger electricity price increase than through regular TOU tariffs. Customers reducing their loads during these periods could lessen the likelihood of system failure or involuntary load shedding.

For the scheme to be successful, it would require customers to have clear knowledge about the program and when the critical periods would be occurring to have the ability to alter their associated demand.

Converse to CPP, the RA notes Bermuda’s minimum system load has fallen of late and may warrant the opposite of CPP. Bermuda experiences spring and fall ‘shoulder periods’ – where neither heating nor air conditioning are heavily used. During these periods daily system load can fall to the point where as few as 3-4 baseload engines need to be operated. This introduces several problems. First, these units were not designed to run at low loads and under these conditions have produced excessive emissions. Second, low load operation reduces fuel efficiency, requiring greater quantities of fuel per unit of electricity produced. Third, on a grid as small as Bermuda’s, when so few engines meet the countries demand a fault on any one engine incurs excessive risk of system instability, a brownout or possible blackout scenario. So, while critical peak pricing and time-of-use pricing may not offer much value to Bermuda, increasing the system’s minimum load could have local environment, fuel efficiency and system stability benefits. The economics of raising the minimum load through incentive rates for using during low load times of day within shoulder periods may be worth exploring. Charging of electric vehicles, for example, might be ideal during this time. It is also worth noting that as renewable penetration increases, minimum load system stability, fuel efficiency and emissions issues on remaining plant will likely exacerbate.

Box 1: Case Study on Australia's Critical Peak Pricing [12,13]

CPP is currently in place in Australia, including through the distributor AusNet. AusNet can call on five Critical Peak Days (CPD) a year between 1 December and 31 March when demand is expected to be significant. During these periods, participating customers can reduce their load to help alleviate the pressure on the network.

Those that participate in the scheme can benefit from reduced energy bills over a 12-month period through lower CPD charges. The CPD charges, which are a component of network costs, are set individually, per customer, based on the average peak usage during the five days (kVA). By decreasing the demand during those peak periods, users can lower their CPD component of the electricity bills and save money on network charges. The CPD charge is calculated by taking the CPD price determined for the periods and the average usage.

Participants are businesses with more than 160 MWh of annual electricity usage. Notifications for potential Critical Peak Days are sent up to 7 days in advance with confirmation being sent the day before (24 hours in advance). It has been found that under CPP, the reduction in peak consumption is typically over four times larger than TOU tariffs.

6.3. Interruptible Rates

An alternative to CPP is Interruptible Rates, or non-firm rates. These would provide payment to customers who reduce their load when called to do so, reducing the likelihood of system failure. This could also include offering a user a lower electricity rate, but in return, the user would reduce their load when told to do so.

Interruptible Rates can also have what is called a "buy-through" provision. This allows the customer to purchase electricity beyond their service agreement at a higher price than their regular rate during the moments of load reduction[14]. This would allow the customer to keep their original demand behaviour for a specific reason instead of reducing load.

[12] https://www.ausnetservices.com.au/cpd

[13] https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Former_Committees/electricityprices/electricityprices/report/c05

[14] https://www.mge.com/customer-service/for-businesses/electric-rates/is-4-electric-interruptible-service

Box 2: Case Study on Barbados' Interruptible Rates[15,16]

Barbados' utility, Barbados Light & Power Company Limited, introduced the Interruptible Service Rider as a two-year pilot program, which was later approved on a permanent basis. The program is available to customers in the Secondary Voltage Power (SPV) and Large Power (LP) tariffs, and those that have a billing demand over 300kVA and a monthly interruptible demand greater than 100kVA. The service is offered on a first-come first-serve basis until reaching 20 customers with an installed capacity of no more than 10,000kVA. Additionally, the customers who are on TOU rates are not eligible to participate in the scheme.

In the scheme, the customer comes into an agreement with Barbados Light & Power Company, in which they determine a Firm Demand Level (FDL), which establishes the load limit of interruption and the value that the customer must reduce the demand to when called on. The minimum FDL is zero. To be eligible, a customer needs to demonstrate that they can reduce their load to the Firm Demand Level (FDL) within 30 minutes of being notified. Additionally, each year, the participating customer is not required to exceed 240 hours of interruption.

The customers are notified of the interruption, or when they must reduce their load, at least 30 minutes in advance of the event, and then are notified when the interruption will end at an appropriate time.

The customers will be credited for the monthly interruptible demand, at specific rates per kVA. The monthly interruptible demand is equivalent to the difference between the average demand of the customer and the FDL. The average demand is the energy (kWh) consumed by the customer for a billing period, divided by the number of hours during the billing period without interruption, and divided by the power factor of 0.85.

The rates that are used to compensate the users vary depending on the agreed times of interruption. There is one rate used for customers that have agreed on interruptions between 8 am – 9 pm on any day except Saturdays, Sundays, and public holidays. There is another rate used for customers that have agreed on interruptions between 8 am – 4:30 pm on any day except Saturdays, Sundays, and public holidays. Additionally, no credit is paid to the customer when the monthly interruptible demand is less than 100kVA.

6.4. Summary

As touched on in this section, there are several forms of time varying pricing that are practiced and are available for consideration.

These options are summarised in Table 7, below.

[15] Fair Trading Commission, https://www.ftc.gov.bb/index.php?option=com_content&task=view&id=297
[16] Barbados Light & Power Company Limited, Interruptible Service Rider, https://www.ftc.gov.bb/index.php?option=com_content&task=view&id=297

Table 7. Summary of Time Varying Pricing

	Business as usual in Bermuda	Cost-based TOU	Non-Cost-Based TOU	Critical Peak Pricing	Interruptible Rates
Variation of pricing	N/A	Based on costs – generally increased prices in peak periods and lower prices in other periods	Based on set ratio or value or other indexation – generally increased prices in peak periods and lower prices in other periods	Increasing prices during stress periods deemed as "critical"	Customers are compensated, or receive lower electricity rates, in return for reduced load when called on
Granularity	N/A	Can be hourly, daily, seasonal, etc.	Can be hourly, daily, seasonal, etc.	The duration and date/time is usually selected by the utility	The duration and date/time is usually selected by the utility
Basis of setting varying prices	N/A	Generation costs – market-based	Indexation or ratio set – can be non-market based	Usually set by utility/regulation	Can be set by utility/regulation

These options have several pros and cons, in particular by looking at their applicability in Bermuda. These considerations are summarised in Table 8 below.

Table 8. Summary of Pros and Cons for Time Varying Options

	Pros	Cons
Business as usual in Bermuda	✓ Current approach is standardised ✓ Requires no further explanation to the public as there is already understanding	– Does not provide any signal to users on when there are network constraints
Cost-based TOU	✓ Reflective of generation costs so it is a market-based approach for setting prices ✓ Could be investigated and considered when there is more renewable penetration	– Lack of renewables does not lead to a large variation of pricing currently in Bermuda – Would not create strong enough signals for users since prices would not vary much

	Pros	Cons
	✓ Can help incentivise EVs and charging times ✓ Can help incentivise consumption during lower consumption periods, and therefore, fewer demand fluctuations, which can help improve efficient system operation in Bermuda	
Non-Cost-Based TOU	✓ Could create strong enough signals for users to reduce their load ✓ Can help incentivise consumption during lower consumption periods, and therefore, fewer demand fluctuations, which can help improve efficient system operation in Bermuda	– Assumes customers would react in time during peak periods – Not necessarily market based – Prices would have to be higher than costs (since costs do not send strong enough signal) which could reduce efficient consumption – Would require public engagement and full understanding for customers to react
Critical Peak Pricing	✓ Can help reduce system stress when needed – during peak periods ✓ Can be applied to seasons/days when the system is in stress ✓ Could create strong enough signals for users to reduce their load	– Assumes customers would react in time – Requires several implementation considerations (i.e., how would "critical" moments be determined, how many periods in a year, duration of the periods, pricing of the periods) – Non necessarily set by the market which requires regulation – Would require public engagement and full understanding for customers to react – Does not necessarily incentivise consumption in lower consumption periods (decrease demand fluctuations) – which could improve efficient system operation
"Inverse" CPP	✓ Can raise minimum system load to increase system stability, minimize base-load engine part load operation fuel efficiency, reduce part-load emissions issues	– May lack any significant pricing incentive opportunity
Interruptible Rates	✓ Could create strong enough signals/incentives for users to reduce their load	– Requires several implementation considerations (i.e., how would the utility decide when to call on those customers, pricing/rates related to those periods)

	Pros	Cons
	✓ Users have to prove they ran reduce their load ✓ Users can be contracted to reduce load to a certain amount ✓ Can help reduce system stress when needed – during peak periods	– Non necessarily set by the market which requires regulation – Would require public engagement and full understanding for customers to be able to react – Does not necessarily incentivise consumption in lower consumption periods (decrease demand fluctuations) – which could improve efficient system operation

7. PROTECTING ELIGIBLE CUSTOMERS

Currently, the Bermuda Government provides financial assistance to some customers. Additionally, there is ongoing customer service support to help customers on a case-by-case basis to determine mutually agreeable payment arrangements of electricity bills. There may be a need to introduce yet further support programs to shield most vulnerable customers ("eligible customers" – where eligibility criteria might extend further than existing programs) from energy poverty. The funding of associated costs from the programs should not create a disproportionate cost burden onto the broader customer base, as non-eligible customers could see the fees reflected on electricity bills or taxes.

Support and protection of eligible customers can include rate-based programs, energy assistance programs, and quantity programs:

- Rate-based programs include lower rates or discounts. These can include applying a discount to the variable/energy rates for eligible customers or waiving the monthly fixed charge.

- Energy assistance programs can include bill assistance plans and electricity bill caps.

  - Bill assistance plans can involve providing eligible customers with a fixed monthly credit. The assistance can be designed so that the credit can only be used for purchasing electricity or so that it can be used for any purpose. It is thought that the latter could lead to more beneficial outcomes.

  - Electricity bill caps are also classified under energy assistance programs. This type of assistance can set a cap on the electricity bill that a user would be charged. The cap could be set on different factors including a percentage of income levels.

- Quantity programs target the electricity consumption levels and include programs which increase energy efficiency and therefore, reduce electricity usage, or those that include pre-paid meters so that customers pay for a specific amount of electricity, working in a similar way to a pre-paid phone card.

Additional support could be considered such as Arrears Management or Arrears Forgiveness Programs for eligible customers. These types of programs incentivise on-time payments by forgiving debt payments. For example, if the customer pays the agreed monthly bill on time, then the utility could forgive past due payments over time. The monthly bill could also be set using the average monthly bill and a part of the due amount.

8. BUDGET BILLING

Volatile monthly bills are a common electricity customers concern. Volatility can arise from issues such as commodity price fluctuations, mostly driven by the Fuel Adjustment Rate (FAR), and variations in customer behaviour which are presently driven by seasonal effects, and in the future could be driven by new appliances, electric vehicle charging and other considerations. Improved rate design can help reduce bill fluctuations; however, consumption patterns and commodity markets are unlikely to change anytime soon. Billing options and practices can help manage the volatility and ability to pay for electricity.

Budget billing, which is common practice in other regions such as the UK, levelises monthly bills based on expected annual usage/bill. Values are specific to individual customers and based on historic usage, which is then used to estimate the average monthly bill. The mechanism creates a balancing account for each customer which helps keep track of the budgeted payments and the actual billing amounts. Adjustments to the monthly payments can be made if the balance becomes too different from actual usage or there are changes in energy costs.

There are several advantages that arise from budget billing. Budget billing allows expenses to be more predictable for customers with less drastic price shocks, which can improve the ease of financial planning. Budget billing can also complement other programs and can help teach socially responsible behaviour, which can help customers learn and practice good financial planning habits.

However, there are some concerns that arise from the implementation of budget billing. Setting up and operating such a program could require additional resources from the utility, increasing costs. Therefore, to be able to recover these expenses, the utility may have to charge operating or implementation fees to provide the budget billing option. Additionally, the intent of the program is for bills to be levelised for as long as possible, however, with unexpected increases or decreases in the market and fuel prices, monthly bills may need to be reviewed and updated more frequently than once a year. There is also concern that budget billing, which aims to fix monthly bills, may reduce customer response to changes in pricing design features (i.e. TOU, CPP, etc.).

9. FEEDBACK FORM

The public is welcome to complete this feedback form and provide any comments or feedback to the RA regarding the relevant topics discussed in this report.

- Updating the Approach to Calculating Rates
- Recovering Costs from Customers with Distributed Generation
- Time-of-Use Pricing
- Critical Peak Pricing
- Interruptible Rates
- Protecting Eligible Customers
- Budget Billing
- Additional comments

Updating Approach to Calculating Rates

Question 1: Do you have a preference out of the presented alternatives for calculating rates? And if so, which alternative is of preference (Option A, B, C, D)?

Question 2: Do you agree that Option A would help improve cost reflectivity and transparency while still ensuring rate continuity and providing a gradual change towards more cost reflective rates?

Question 3: How important is it to have rates that accurately reflect the costs to provide specific services, considering that this may increase tariff complexity?

Question 4: Do you have a view on the ideal proportion of revenue recovery / total bill that should come from fixed versus variable charges?

Question 5: Do you think an inclining block rate is still appropriate for residential customers? And commercial customers?

Question 6: Do you think it is still appropriate to have the GFC tiers in place?

Recovering Costs from Customers with Distributed Generation

Question 7: Do you think that – to mitigate the risk of volume-driven price shock for all customers – there should be separate customer class rates for customers with distributed generation to correctly recover DG costs, where the standing charge would be higher than for other customers without DG?

Question 8: Do you think that indirect network reinforcement costs caused by DG penetration should be recovered from all customers, irrespective of whether they have DG or not?

Question 9: Do you think that the costs arising from providing subsidies to distributed generators, through the FiT, should be recovered from the broader customer base, regardless of if they benefit from the FiT or not?

Time-of-Use Pricing

Question 10: Do you think cost-based Time-of-Use pricing would be appropriate for Bermuda?

Question 11: Do you think the RA should consider non-cost-based Time-of-Use pricing for Bermuda?

Critical Peak Pricing (CPP)

Question 12: If you consider that CPP should be explored, which customer classes should be exposed to CPP? Do you consider that most commercial customers would be able to respond to CPP?

Question 13: Should the CPP be set based on the expected value of lost load or some other measure?

Question 14: How many critical days/periods should BELCO be able to call? How many hours, maximum, during the critical day should be priced at the higher level?

Question 15: Should the CPP be mandatory for some types of customers? If so, which ones?

Question 16: How much lead time would be reasonable to alert customers to a critical day/period? What information interface would be best to communicate with customers (e.g., text, web-based, media/press releases, etc)?

Interruptible Rates

Question 17: If Interruptible Rates are explored, should customers have the right to "buy-through" instead of interrupting load? If so, what should the rate be based on?

Question 18: Should payment be provided for customers participating in the scheme outside of direct demand reductions?

Question 19: Since Interruptible Rates purchase capacity in units of kW, how should the capacity price be reflected? Should prices change based on conditions of the contract (e.g., length of notice, direct load control, time/days which were agreed for interruption, etc)?

Question 20: How much lead time is reasonable to alert customers for when they would have to reduce load?

Question 21: Should Interruptible Rates be mandatory for some types of customers? If so, which ones?

Question 22: Which option, if any, out of those discussed in Time Varying Pricing, do you think would be most suitable for Bermuda? (Traditional cost-based TOU, non-cost-based TOU, Critical Peak Pricing, Interruptible Rates)

Protecting Eligible Customers

Question 23: Do you think there should be additional support programs for eligible customers that are deemed most vulnerable? If so, what do you believe eligibility criteria should be and do you have a preference in the type of program out of those listed and mentioned in the report?

Question 24: Would you support the additional programs if they were to be funded by the broader customer base?

Budget Billing

Question 25: Do you think the RA should consider introducing Budget Billing for Bermuda?

Question 26: Do you think the utility should seek to recover additional prudently incurred operating costs from offering Budget Billing directly from customers who benefit from it, or from all customers?

Question 27: Do you think you would benefit from Budget Billing? Would you subscribe to such a program – if this was provided at no additional cost to customers? What if this was provided at an additional cost to customers?

Additional Comments

If you have any additional comments, feel free to provide them below.