FAIR TRADING COMMISSION

BARBADOS **FTCUR/REVRER-2016-02**

FAIR TRADING COMMISSION

IN THE MATTER of the Fair Trading Commission Act, CAP. 326B of the Laws of Barbados;

AND IN THE MATTER of the Utilities Regulation Act, CAP. 282 of the Laws of Barbados;

AND IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003 and the Utilities Regulation (Procedural) (Amendment) Rules, 2009;

AND IN THE MATTER of the Motion to Review the Renewable Energy Rider Decision of August 8, 2014 pursuant to Section 36 of the Fair Trading Commission Act, Cap. 326 of the Laws of Barbados

BEFORE:

Mr. Jefferson Cumberbatch	Chairman
Dr. Philmore Alleyne	Commissioner
Mr. Dawood Pandor	Commissioner
Ms. Monique Taitt	Commissioner
Mr. Andrew Willoughby	Commissioner

NOTICE OF MOTION TO REVIEW

TAKE NOTICE THAT the Fair Trading Commission (the Commission) will be moved on the 22nd day of April 2016 to commence a Motion to review and vary the August

8th, 2014 Decision on the Renewable Energy Rider regarding the determination on the Renewable Energy Rider credit and expansion of the eligible capacity limit.

MOTION TO REVIEW

1. In accordance with Section 36 of the Fair Trading Commission Act, Cap. 326 (FTCA) of the Laws of Barbados the Commission may, on application or on its own motion, review and vary or rescind any decision or order made by the Commission and where under this Act a hearing is required before any decision or order is made, such decision or order shall not be altered, suspended or revoked without a hearing.

2. The Renewable Energy Rider (RER) was approved by the Commission on the 8th of August, 2014, as a scheme to facilitate the sale of surplus electricity generated from the Barbados Light & Power Co. Ltd.'s (BL&P) customers' distributed Renewable Energy (RE) systems.

3. At a meeting on February 29, 2016, attended by the Commission and other relevant stakeholders, inclusive of RE installers, the Minister of Industry, International Business, Commerce and Small Business Development, the Minister responsible for Energy and Telecommunications and the BL&P, RE sector representatives requested the introduction of an interim floor credit until such time as permanent tariffs are determined. It is based on these discussions and our understanding of the current operating conditions that the Commission proposes a review of the RER credit.

4. Additionally, the Commission is aware that the Electric Light & Power Act, 2013 (ELPA) which was proclaimed in May 2015, does not restrict individual installed capacity and requires that all licensed RE generators, whether or not they are BL&P customers, be afforded the opportunity to sell electricity to the grid. It is under this consideration that the Commission proposes to revisit the capacity limits of the RER.

5. The Commission has the authority to initiate the proceedings by way of Motion. The Commission is therefore bringing this Motion for review of the RER in accordance with Section 36 of the FTCA, as given in paragraph 1.

6. The Commission will initiate this Motion by way of a written consultation in accordance with the principles of natural justice. The Commission, as a regulator of electricity services, must be open and fair in its decision-making process. The written consultation is a means of ensuring that the level of transparency in its review of the Decision on the Renewable Energy Rider is maintained. Service providers, representatives of consumer interest groups, RE installers and any other parties that have an interest in the matter are invited to submit written responses to the consultation.

The Components of the Renewable Energy Rider (RER) that are Relevant to the Motion

7. Under the current RER the following conditions apply:
   a. **Value of Permanent RER Credit -**

      "The Commission has approved the RER credit of 1.6 times the fuel clause adjustment (FCA)";

   b. **Minimum Credit -**

      "The Commission has determined that no predetermined minimum credit shall apply";

   c. **Capacity Limit -**

      The individual customer capacity limit of 1.5 times the customer's current average usage up to a maximum capacity of 150kW is accepted. This average usage is normally calculated based on the most recent 12 months that the customer relied on the grid. It must be noted that the RER credit at 1.6 times the FCA will only be applicable to a maximum of 1.5 times the

customer's average usage, thereafter RER customers will be reimbursed at 1 times the FCA";

The complete set of terms and conditions of the current RER may be found at Appendix 1.

8. The primary purpose for the review of the RER, at this time, is to address the financial concerns of current and prospective RE generators and installers due to the low value of the RER credit, which is occasioned by the general plummeting oil prices on the international market, and the current un-competitiveness and economic unviability of the RER credit.

9. Additionally, the Motion considers the expansion of the RER programme to allow it to be accessible to generators with capacities up to 500kW. This Motion is focused on the temporary establishment of an RER credit that will offer a level of compensation to RE generators such that RE generation is economically viable in an environment of low oil prices. This approach deviates from what currently obtains, as the existing RER credit is directly linked to the FCA, which is based on the BL&P's oil purchase price and varies from month to month without a specified minimum rate. The present approach renders RE generators completely vulnerable to the vagaries of the international oil market; an industry that is being developed and positioned by the Government to contribute to the transformation of this country's future security of supply status and to reduce the outflow of foreign exchange.

<u>Approaches Under Consideration</u>

<u>Price Floor Credit</u>

10. Currently, the RER credit is designed under the avoided cost approach as articulated in earlier drafts of the 2012 National Sustainable Energy Policy (NSEP). However, there has been considerable debate as to the merits of applying avoided cost versus resource cost. The former, regardless of its design, values RE generation on the basis of the fixed and variable costs that the incumbent utility would have otherwise incurred had they been required to generate in the absence of RE generators, typically using fossil fuels.

11. Conversely, the resource cost is typically based on the levelised cost of energy (LCOE). LCOE is a static measure of costs which is the computed price where revenues would equal RE project costs, plus a reasonable profit. The LCOE of RE technologies reflects multiple factors: resource quality; equipment cost and performance (including capacity factor); the balance of project costs; fuel costs (if any); operation and maintenance costs; the economic lifespan of the project and the cost of capital.

12. Under the pilot phase of the RER, which commenced on July 1, 2010, an RER credit floor of $0.315 was applicable. The offer of a floor was discontinued in the BL&P application for the permanent implementation of the RER. It must be noted that the application was made in an environment of high and increasing oil prices (US $100+/barrel) and at a time when the prospect of a US $30 - 40/barrel oil price, which currently exists, was unforeseen.

13. Representatives of the RE sector, at the February 29, 2016 meeting, tabled the implementation of a floor rate to mitigate the negative economic impacts that have been precipitated by persistent, low oil prices and to offer a level of price security/stability. This credit would act as the minimum that could be paid to generators and would operate in conjunction with the already established variable RER credit once the latter is at or above such a floor. This approach allows variation in the value of the RER credit in line with market conditions

but would establish the minimum payment. Under this approach, some uncertainty remains present but is constrained by the setting of a lower limit.

14. Traditionally, price floors are used by the regulator, be it an independent agency or a government agency, to ensure the economic viability of producing or providing a particular commodity. The argument for the implementation of a price floor, in this case, is to protect RE generators against the falling price of fossil fuel, to which the FCA and the RER are directly linked.

15. For balance and fairness, the Commission considers that, with the institution of a floor, a simultaneous introduction of a ceiling would be required. This gives equal consideration to both the RE generators and the purchasing utility.

16. The Barbados Renewable Energy Association (BREA), on March 29, 2016, submitted an application to the Commission for a review of the August 8, 2014 RER Decision. This submission was made after the Commission had commenced its internal process for a review of the RER on the basis previously outlined. It was considered that the Commission should proceed with its Motion while giving due consideration to BREA's application.

17. In its submissions, BREA advocated the introduction of a minimum credit of BB$0.40 per kWh. BREA referenced BB$0.40 as the lowest price that should be paid per kWh in order to attract the required investment by customers with RE systems and for financial institutions to support such projects. BREA advised that their proposed credit was based on an assessment of payback periods. The proposal did not include a ceiling credit. BREA also included other requests in its application that are outside the immediate scope of this Motion. The full submission, which outlines the considerations employed and the association's specific requests, is attached at Appendix 2.

18. Where the implementation of a floor and ceiling credit is chosen, the credit will operate such that the minimum credit would become applicable where the per unit value of the RER credit is at or below this stated floor credit. Where the per unit value of the RER credit is above this minimum floor, that credit shall apply up to the specified ceiling credit. Where the computation of the RER credit is the ceiling credit or greater than the ceiling credit, the specified ceiling credit shall apply.

19. Additionally, RER credit shall continue to be compensated at the applicable value, as given in the paragraph above, up to a maximum kWh of 1.5 times the customer's average usage, based on the most recent twelve months. Thereafter, customers are compensated at 1 times the FCA.

Fixed Credit

20. In addition to the above, the Commission considers that the harm which this Motion is seeking to alleviate may also be addressed with the introduction of a fixed credit.

21. Prior to the RE installers tabling the RER credit floor at the February 29, 2016 meeting, the BL&P placed, on January 29, 2016, a recommendation before the Commission for the setting of fixed RE compensation credits (see Appendix 3 for full report). The BL&P presented fixed credits based on avoided cost, resource cost and social value. The latter approach seeks to quantify the value of the resource to society. Along with the typical benefits of utilizing a renewable resource, it also considers foreign exchange savings, environmental benefits and electrical loss savings. This approach is, however, the most subjective of the three.

22. The BL&P has tabled fixed credits and not floor credits. The Company is not in favour of the use of floor credits for compensating distributed RE generators. It is of the view that fixed long term credits, as proposed in its submissions to the Commission, offer the necessary price certainty to the RE sector. It argues

that the fixed long term credits proposed were developed using established industry methodologies for pricing renewables and is an acceptable basis for delinking compensation from fuel costs.

23. It is the Commission's understanding that the Ministry of Energy is proposing the use of feed-in-tariffs as the permanent support mechanism for compensating RE generation. Feed-in-tariffs are congruent with the concept of fixed credits.

24. Further, the BL&P has recommended use of the resource cost approach for valuing distributed scale RE systems (systems ≤ 500kW) (BB$0.378kWh and BB$0.298/kWh for solar PV and wind, respectively) and the application of the avoided cost approach in valuing utility scale systems (systems > 500kW) (BB$0.342/kWh and BB$0.284/kWh for solar PV and wind, respectively).

25. Prior to the BL&P's January 29, 2016, submission, the Commission was consulted on the assumptions and methodology used by the utility in arriving at its recommended rates.

26. Recent local and international discussion on the various pricing approaches appears to suggest that the resource cost approach is emerging as the preferred option. This approach appears to be appropriate, especially as it pertains to tropical island grids which contend with security of supply issues, foreign exchange drain and high and volatile oil prices, while being blessed with abundant local renewable solar and wind resources that aid in enhancing grid stability when deployed at the distributed scale. Resource costing disaggregates RE costs from the cost of fossil fuels and offers the much desired stable pricing of the electricity generated from these sources.

27. Pre-specified fixed credits offer assurances and predictability to generators, the types of guarantees and stability that RE generators are seeking. They do this by providing a safeguard against risk brought on by fluctuating fuel prices over time. Conversely, fixed credits also act to constrain the upper bound of any RE

credit that is linked to the cost of fuel when market forces become favourable for such movement.

Capacity Limit

28. The ELPA at Section 13 (1) and (3) requires the utility to interconnect licensees or persons who own, control or operate renewable energy generation systems (suppliers) at their request and to purchase electricity at rates agreed to by the parties and approved by the Commission. It does not limit individual installed capacity, and makes provision for all licensed generators to have access to the grid regardless of whether the generator is or is not a customer of the utility. The Commission is concerned that some generators exist who are currently ineligible to participate in the RER due to its capacity restriction of 1.5 times a customer's average monthly usage up to 150kW. In view of the ELPA, the Commission considers it prudent to revise the allowed individual installed capacity conditions of the RER. It is proposed that it be expanded to 500kW.

29. Where a fixed credit is chosen, that specified fixed credit shall apply to all electricity sold to the grid.

30. **The Commission is seeking input, from all relevant stakeholders, on the utilization of a floor credit or a fixed credit based on the resource cost approach for the RER credit for small distributed generators (≤ 500 kW) and the expansion of the RER capacity limit to 500kW. The fixed credits under consideration are BB$0.378/kWh for RE generated from solar photovoltaics and BB$0.298/kWh for RE generated from wind.**

31. **The determined interim RER credit/s will be applicable until such time as permanent tariff structures are determined.**

32. **Questions**

a) **What are your views on the use of a floor RER credit? What are your views on the use of a fixed RER credit? Please provide the relevant supporting information.**

b) **Should the RER credit be delinked from the price of oil?**

c) **What are your views on the use of the avoided cost approach versus the resource cost approach for the determination of a fixed RER credit? Please provide the relevant supporting information.**

d) **Should the RER credit of 1.6 times the FCA apply to all electricity generated from the renewable energy source or only up to 1.5 times the customer's usage?**

e) **Should generation in excess of the 1.5 times the customer's average usage be computed at 1 times the FCA or at the floor RER credit?**

f) **What are your views on the expansion of the RER programme to include generators with capacities up to 500kW?**

Consultation Process

33. The Commission is specifically charged under the Fair Trading Commission Act, Cap. 326B to consult with interested persons when it is discharging certain functions.

34. This requirement generally involves the Commission issuing a consultative document, in which the Commission:

a. brings to public attention important issues relating to utility regulation in order to promote public understanding and debate;
b. puts forward options and/or proposals as to the approach to adopt in dealing with these issues, to seek to resolve them in the best interests of the consumer, the service provider and the society at large; and

c. invites comments from interested parties, such as consumers, service providers, businesses, professionals and academics.

35. The views and analyses set out by the Commission in a consultative document are intended to invite comments which may cause the Commission to revise its position.

36. If considered appropriate, respondents may wish to address other aspects of the document for which the Commission has not prepared specific questions. Failure to respond to all identified issues will in no way reduce the consideration given to the entire response.

Confidentiality

37. The Commission is of the view that this consultation is largely of a general nature. The Commission expects to receive views from a wide cross section of stakeholders.

38. Respondents should therefore ensure that they indicate clearly to the Commission any response or part of a response that they consider to contain confidential, commercially sensitive or proprietary information.

Responding to this Motion to Review

39. The Commission invites and encourages written responses in the form of views or comments on the matters discussed in the Paper from all interested parties, regulated utilities, other licensed operators, government ministries, non-governmental organisations (NGO'S), consumer representatives, residential consumers, businesses of all sizes and their representatives, the academic community and all other stakeholders.

40. The consultation period will begin on Friday, April 22, 2016 and end on Friday, May 13, 2016. All written submissions should be sent to the Commission by this

deadline. The Commission is under no obligation to consider submissions received after 4:00 p.m. on Friday, May 13, 2016.

41. Copies of this Consultation Paper may be collected between the hours of 9:00 a.m. and 4:00 p.m., Monday to Friday, during the consultation period from the Commission's offices at the following address:

Fair Trading Commission
Good Hope
Green Hill
St. Michael
BB12003
BARBADOS

42. The Consultation Paper may also be downloaded from the Commission's website at www.ftc.gov.bb

43. Persons may submit their response either in written or electronic format.

44. Mailed or hand delivered responses should be addressed to the Chief Executive Officer at the above mailing address.

45. Responses in electronic format may be prepared in either Word or PDF format, attached to an e-mail cover letter and forwarded to info@ftc.gov.bb.

46. Responses may be faxed to the Commission at (246) 424-0300.

Analysis of Responses

47. The Commission will seek to explain the basis for its judgments and, where it deems appropriate, give the reasons why it agrees with certain opinions and disagrees with others. In the interest of transparency and accountability, the reasons for any modifications as a result of the consultation will be set out and, where the Commission disagrees with responses or points that were commonly made, it will, in most circumstances, explain why.

Appendix 1: The Present Renewable Energy Rider (RER)

Under the current RER the following conditions apply:

a. Billing Arrangement

(i) All new Domestic/General Service and Employee RER customers with renewable generating systems with a capacity of 2kW and below will have the option to choose either the "sale of excess" or "buy all/sell all" billing arrangement. This choice of the selected billing arrangement will remain in place for the duration of the contract;

(ii) All new Domestic/General Service and Employee RER customers with renewable generating systems above 2kW will be billed under the "buy all/sell all" billing arrangement;

(iii) All new SVP and LP RER customers will be billed under the "buy all/sell all" billing arrangement;

(iv) All existing RER customers may remain with their current billing arrangement or exercise the option, within three (3) months of the effective date of this Decision, to change from "sale of excess" to the "buy all/sell all" billing arrangement.

The term *"existing"* refers to RER customers who, before September 1, 2014, were connected to the Applicant's Grid under an agreed billing arrangement.

b. Metering System

Meter Configurations 1 and 2 are both permitted. Meter Configuration 2 is however not available if the "sale of excess" billing arrangement is chosen.

c. Value of Permanent RER Credit -

"The Commission has approved the RER credit of 1.6 times the FCA";

d. **Minimum Credit -**

"The Commission has determined that no predetermined minimum credit shall apply";

e. **Capacity Limit -**

The national intermittent capacity is set at 20 MW of distributed RE with reservation of 1MW of the last 3 MW of capacity for residential customers (customers in the Domestic Service, General Service & Employee classes) once the first 17 MW of capacity has been allocated.

The individual customer capacity limit of 1.5 times the customer's current average usage up to a maximum capacity of 150kW is accepted. This average usage is normally calculated based on the most recent 12 months that the customer relied on the grid. It must be noted that the RER credit at 1.6 times the FCA will only be applicable to a maximum of 1.5 times the customer's average usage, thereafter RER customers will be reimbursed at 1 times the FCA";

f. **RER Customer Reimbursement of Credit -**

"The Applicant shall reimburse RER customers on a quarterly basis where the applicable credit is greater than or equal to $100.00";

g. **Contract Period -**

"That RER customers shall be offered a contract for access to the grid for a minimum of 10 years. The value of the RER [credit] shall be subject to review every three years from the date of implementation of this Decision".

Appendix 2: BREA's Application to Review the RER

March 23, 2016

The Chief Executive Officer
Fair Trading Commission
Good Hope
Green Hill
St Michael

Dear Madam

Re: Application to Review the Renewable Energy Rider in Accordance with Section 16 CAP 282 Utilities Regulation

In accordance with Section 16 of CAP 282 Utilities Regulation Act, the Barbados Renewable Energy Association (BREA) is submitting this application for the Fair Trading Commission (FTC) to review the Renewable Energy Rider (RER) and to revise it to allow for a minimum credit of 40 cents/kWh to be paid by Barbados Light & Power Co. Ltd. (BL&P) to customers for energy produced by renewable energy (RE) systems on the "buy all, sell all" billing arrangement and for energy exported by those on the "sale of excess" billing arrangement. We also request that the FTC set the minimum credit so that whatever it is at the time a customer installs his/her RE system it will not fall below that level over the life of their RE system, up to a maximum of 20 years.

At the meeting convened by the Honourable Donville Inniss, Minister of Consumer Affairs with several stakeholders of the RE sector on March 2, 2016, several issues regarding the development of renewable energy in Barbados were discussed. One of the issues focused on at the meeting was the need for policy direction to be given to FTC from the Minister of Consumer Affairs with regards to the RER.

At the conclusion of the meeting, the Minister directed the FTC to review the RER Programme with the intent to establish a minimum credit ("floor") at which the utility would reimburse a customer on the "buy all, sell all" basis for energy produced by their RE system.

The permanent RER Programme has been in place since September 1, 2013, following the FTC's decision of August 9, 2013. This decision followed a two-year pilot project that started in June 2010 and the subsequent application in July 2012 by BL&P for the establishment of a permanent programme.

In their decision of August 9, 2013, the FTC, among other things, set a credit for the reimbursement for energy produced by RE systems up to 150 kW on the "buy all, sell all basis" at 1.6 x Fuel Clause Adjustment (FCA). While there was a minimum payment of 31.5 cents/kWh included in the original pilot programme, the FTC disallowed BL&P's request to have an alternative formula put in place because of its complexity (see bullet 2 of the FTC's decision on page 10) and no minimum credit was provided for in the new programme. However, they indicated in their decision that "consideration can be given to a minimum credit at a subsequent time in the event that the value of the FCA decreases…".

The low oil prices over the past several months have benefitted electricity consumers through significant price reductions in their electricity bills and the country as a whole through lower cost of imports. However, because of the way the RER credit is structured, the low oil prices have significantly reduced the return customers on the RER programme are able to earn on their RE investments and has become a significant barrier to customers investing in these systems. As a result, the renewable energy industry, which has been growing and providing employment to many Barbadians over the past several years, has been placed under threat at a time where the country should be investing in this technology.

The Barbados Renewable Energy Association (BREA), therefore, supports the Minister's directive for the establishment of a minimum credit to be paid to customers on the RER programme for the energy produced by their systems. BREA believes that customers should be encouraged to invest at this time of low fuel costs when the country can most afford it so as to put the customers and the country in a position to mitigate the impact of future increases in oil prices.

BREA's analysis has determined that a minimum credit of 40 cents/kWh is the lowest price that should be paid for each kWh produced by the RE system on the RER programme in order to attract the required investment by customers in RE systems and for banks and other finance companies to finance these projects. While the introduction of a minimum credit of 40 cents/kWh will mean that whenever the FCA falls below 25 cents/kWh the renewable energy customer will be subsidised by the wider base of customers, the impact of this subsidy is very small and is a very small price for customers, and the country as a whole, to pay in the short-term to mitigate against any increases in future oil prices.

The impact of this subsidy is shown below:

Tariff	Customer Energy Use	Customer Bill with FCA at $0.25/kWh	Customer Bill with FCA of $0.13/kWh	Customer Bill with Adjusted FCA due to subsidy (Total 10 MW capacity installed)	Customer Bill with Adjusted FCA due to subsidy (Total 20 MW capacity installed)
DS	300	$154	$113	$114	$116
SVP	10,000	$4,860	$3,671	$3,714	$3,757
LP	100,000	$45,800	$33,910	$34,343	$34,777

This table shows, for example, that at the current low FCA rate of 13 cents/kWh, even with the subsidy due to the minimum credit of 40 cents/kWh in place with a total of 20 MW of capacity installed sometime in the future, the customer would be paying $116 in electricity which is substantially less than $154 they were paying not so long ago when the FCA was at 25 cents/kWh and only slightly above the $113 they are paying now with no subsidy in place.

In addition to this, our investigation has identified that a major barrier for banks and other financing companies to finance RE projects is the uncertainty there is in the expected returns because of the short term nature of the rates (up to 5 years) compared to the period of lending (usually 10 years). We therefore request that with the establishment of the minimum credit, the FTC mirror the mechanisms used by regulators in several countries for feed-in tariffs, and set the minimum credit for the life of the customers' system or 20 years, whichever is lesser. This would mean that, even if at any subsequent rate review the RER rate and/or minimum credit are changed, the credit that BL&P will pay to a customer for energy produced will never fall below the 40 cents/kWh minimum, or whatever the minimum is in place at the time that a customer's RE system is installed, over the life of the customer's system (or 20 years, whichever is the lesser)

We recognise that it may take some time for the FTC to establish the minimum credit. Therefore, in the interest of expediency to save what many think of as a dying renewable industry, the FTC use its regulatory powers to put establish the minimum of 40 cents/kWh immediately as an interim measure.

We also recommend that, recognising it may take some time for BL&P to make the changes to their billing system to accommodate the introduction of the minimum credit, the FTC instruct BL&P to prepare for this change immediately so that they are ready to implement the change as soon as the decision is communicated.

So in summary, BREA is requesting the following in this application:

1. The establishment of a minimum credit of 40 cents/kWh to be paid by BL&P to customers in the RER Programme for energy produced by renewable energy (RE) systems on the "buy all, sell all" billing arrangement and for energy exported by those on the "sale of excess" billing arrangement.
2. The established minimum that is in place at the time a customer installs their RE system be the minimum credit that customer will receive for their energy sold to BL&P over the life of their system or 20 years, whichever is lesser.
3. Immediately implement a minimum credit of 40 cents/kWh as an interim measure to stop the fall-out of the renewable industry presently being experienced and revise it, if necessary, on completion of the FTC's consultation process.
4. Immediately instruct BL&P to make adjustments to their billing system to accommodate minimum rate in the calculation of the credit immediately after the decision by the FCT is handed down.

We look forward to your urgent consideration and implementation of this request.

Yours Sincerely
THE BARBADOS RENEWABLE ENERGY ASSSOCIATYION

Clyde Griffith
Executive Director

BREA SUPPORTING DOCUMENT FOR MINIMUM CREDIT OF 40 CENTS/kWh

For some time, the Barbados Renewable Energy Association (BREA) has been monitoring the impact of reducing fuel prices on the viability of investments in the renewable Energy sector.

At the current Fuel Clause Adjustment (FCA) of 13.1 cents/kWh the estimated payback for a 100 kWp system has increased substantially to in excess of 15 years. As a result, many customers who were previously interested in investing in Photovoltaic Systems and/or micro-wind systems are no longer willing to do so. This has resulted in a significant slowdown in the Renewable Energy Industry and will significantly impact the achievement of Government's stated renewable energy objectives.

BREA made an application to the Fair Trading Commission dated March 23, 2016 requesting:

1. The establishment of a minimum credit of 40 cents/kWh to be paid by BL&P to customers in the RER Programme for energy produced by renewable energy (RE) systems on the "buy all, sell all" billing arrangement and for energy exported by those on the "sale of excess" billing arrangement.

2. The established minimum that is in place at the time the customer installs their RE system be the minimum credit that customer will receive over the life of their system or 20 years, whichever is lesser.

3. Immediately implement a minimum credit of 40 cents/kwh as an interim measure to stop the fall-out of the renewable industry presently being experienced and revise it, if necessary, on completion of the FTC's consultation process.

4. Immediately instruct BL&P to make adjustments to their billing system to accommodate minimum rate in the calculation of the credit immediately after the decision by the FCT is handed down.

While BREA believes that the minimum credit should be in excess of 40 cents/kWh – a reasonable number could be as high of 45 cents/kWh - it has proposed 40 cents/kWh since this number has been long discussed and seems accepted by many to be a number that the industry could work with, as long as there is some certainty that this minimum credit could be in place for the life of the system.

In the following table the payback periods and returns over the 20 year period are shown for different size systems using estimated costs per peak Watt of panels installed and includes conservative (lower) estimates of Maintenance and Insurance costs. The estimates of the installed costs used may even be very challenging for some installers to achieve.

However, we are using these to show that, even using these conservative numbers the payback is below the threshold of 7 years that some investors and financers may consider to be reasonable.

Size (kWp)	5 kWp	10 kWp	25 kWp	50 kWp	100 kWp	150 kWp
BDS$/Wp	$6.00	$5.50	$5.00	$4.50	$4.00	$3.90
Payback (years)	11.4	10.2	9.2	8.2	7.2	7.4
Return over 20 years	7.07%	7.65%	8.34%	9.16%	10.16%	9.13%

We have also analysed this by removing the Maintenance and Insurance costs and have found that the payback would improve - with the 5 kWp reducing to 9.7 years, 10 kWp to 8.9 years, 25 kWp to 8 years, 50 kWp to 7.2 years, 100 kWp to 6.4 years and 150 kWp to 6.6 years. However, it may be unrealistic to expect that, even though some customers may have the bargaining power and capability to reduce these maintenance and insurance costs, it is unlikely that these could be removed entirely.

Appendix 3: BL&P's Proposed RE Tariffs

COMPENSATING RENEWABLE ENERGY GENERATION

APPROACH RECOMMENDATIONS

Background

Renewables are anticipated to play an important role in the future energy mix of Barbados. In recognition of the potential benefits of renewable energy, the Barbados Light & Power Company (BLPC) in March 2010 obtained permission from the Fair Trading Commission (FTC) to introduce the Renewable Energy Rider (RER) to facilitate the integration of renewable generation into the national grid. Since 2010, the country has witnessed significant growth in distributed renewable energy adoption, particularly installations of solar photovoltaic (PV) systems. Installed PV generation capacity has grown from less than 10 kW in 2010 to 9.4 MW at the end of 2015. While currently renewable energy generation represents approximately three percent of the total overall generation capacity, its share is likely to increase with the recent amendments to the Electric Light & Power Act (The Act). The Act was proclaimed in May, 2015 and is intended to facilitate the interconnection of any licensed renewable energy supplier that is desirous of supplying power to the public grid. An important question therefore emerges as to how these suppliers should be compensated for the electricity they supply to the grid.

Compensation Philosophy

The adoption of renewable energy resources for electricity generation will provide benefits of environmental conservation, energy security, reduced dependency on imported fossil fuels and the saving of scarce foreign exchange to the country. BLPC views stabilization and possible reduction in electricity prices as central benefits of implementing such technologies. However, these factors may need to be balanced against societal needs and the desire of investors to make a reasonable rate of return. BLPC considers an analysis of the levelized cost and or value of the renewable energy resource to be a good starting point for determining appropriate compensation.

Levelized cost and value being the expected lifetime cost or value of the RE resource divided by its expected lifetime power output.

RE Resources

The Act seeks to facilitate the supply of renewable energy by suppliers. The Act makes no distinction between distributed renewable generation and utility-scale renewable generation. We define distributed renewable generation as relatively small-scale generation from renewable sources that are connected to the public grid at the distribution voltage level. For the purpose of rate design RE suppliers with an AC output of **500 kW or less** are classified as distributed renewable generation. Utility-scale generation refers to RE resources with an AC output **greater than 500 kW** that are either connected at the transmission or distribution voltage level.

Figure 1: Customer Types

Customer Type	Capacity
Distributed Renewable Generation (DRG)	≤ 500 kW
Utility Scale Generation (USG)	> 500 kW

Renewable generation may consist of a range of technologies including solar photovoltaic, wind turbines, biomass, waste to energy, anaerobic digestion and solar thermal, however focus is given in this document to pricing supply from wind, solar photovoltaic and biomass technologies as these are current areas of interest expressed by suppliers.

Compensation Options

Three price-setting methodologies were explored for the development of compensation options for RE resources. The approaches considered included pricing based on avoided cost, cost of the RE technology and social value.

Avoided Cost Approach

The Avoided Cost Approach considered the fixed and variable costs of BLPC's generating plants that could be avoided by obtaining energy from RE suppliers. That is, the energy and/or capacity cost that BLPC would incur if the energy was generated by their generators as opposed to purchasing it from RE suppliers.

To calculate avoided cost, BLPC used the differential revenue requirement (DRR) method which calculates the difference in BLPC's overall generation cost with and without the RE resource. Optimization of the expected long-run expansion plan was conducted with and without the potential RE resource. The PLEXOS production and simulation modelling software employed in the development of the 2012 Integrated Resource Plan was used to determine the avoided cost for each technology using the methodology presented in the IRP report. The model considered planned plant retirements, fuel and demand projections in determining the optimal or least-cost plant additions from a list of candidate plants with specified operating characteristics (see Appendix A). The avoided cost is the present value of the difference in total generation costs with and without the RE resource. Figure 2 displays the calculated avoided cost differentiated by RE resource technologies. A more detailed description of the methodology and assumptions is provided in Appendix A.

Figure 2: Estimated 2016 Avoided Costs

Technology	Levelized Avoided Cost	
	Capacity Cost BB$/kW/yr	Energy Cost BB$/kWh
Solar photovoltaic	-	$0.342
Wind	-	$0.284
Biomass	$186.5	$0.194

Resource Cost Approach

The Resource Cost Approach is based on the levelized costs of the RE resource, plus a targeted return to the RE investor. This resource cost approach essentially seeks to provide a rate to the RE developer that covers their RE project cost and provide an estimated profit. The levelized costs are shown in Figure 3 and further details on the assumptions and methodology are discussed in Appendix B.

Figure 3: Estimated Resource Cost 2016 Levelized Tariff

Technology	Levelized Cost ($/kWh)
Solar photovoltaic	$0.378
Wind	$0.298

Social Value Approach

The Social Value Approach estimates the value of energy to society from the renewable energy resources. The approach adopted is a variation to the methodology adopted by Minnesota Department of Commerce in valuing distributed photovoltaic generation (See Appendix C). Our approach assumes that local benefits to be derived from RE resources relate to foreign exchange savings, electrical loss savings, energy savings including variable O&M costs, generation capacity savings and environmental benefits. The estimated social values of the intermittent RE resources are represented in Figure 4. Further details on the assumptions and methodology are provided in Appendix C.

Figure 4: Estimated Social Value 2016 Levelized

Technology	Levelized Value ($/kWh)
Solar photovoltaic	$0.341
Wind	$0.254

Compensation Recommendations

The three approaches investigated to develop rates for compensating RE resource suppliers provided different estimates of the value of RE resources. A summary of the approaches and estimated prices are shown in Figure 5.

Figure 5: Estimated Prices

	Solar Photovoltaic	Wind	Biomass

Approach	Energy ($/kWh)	Energy ($/kWh)	Energy ($/kWh)	Capacity Cost ($/kW/yr)
Avoided Cost	$0.342	$0.284	$0.194	$186.5
Resource Cost	$0.378	$0.298	-	-
Social Value	$0.341	$0.254	-	-

The BLPC recommends the avoided cost approach for valuing all utility-scale RE resources (systems > 500kW) and the resource cost approach for valuing the distributed scale RE resources (systems ≤ 500kW). The social value approach was examined for comparative purposes for the Commission's review and consideration. We do not recommend that this approach be used as a first option at this time in either case as estimating the social value has more subjective assumptions.

Our recommendation that the avoided cost approach be adopted to determine the prices for utility scale RE projects is based on it being the most internationally established method for determining the value of such projects. The resource cost approach for pricing the smaller distributed projects is suggested as a means to acknowledge the geographical diversity that this type of generation provides over utility–scale projects. The results from the Intermittent Penetration Study recently conducted by General Electric (GE) on behalf of BLPC confirmed that there are benefits to be derived from having the geographical diversity provided by solar PV systems that are spread across the island. The distributed systems thus help minimize the impact of grid instability caused by the inherent intermittent nature of these technologies. However, distributed systems often do not benefit from the lower pricing due to economies of scale that are associated with larger projects.

The BLPC recommend that a fixed rate of $0.342 per kWh and $0.284 per kWh be considered respectively for **utility-scale** Solar and Wind energy supplied to the grid. We further recommend that a fixed rate of $0.378 per kWh and $0.298 per kWh be applied respectively to **distributed** Solar and Wind energy supplied. BLPC does not share the opinion of some stakeholders that a floor and or a ceiling on the compensation are necessary. BLPC holds the position that the fixed long-term rates recommended would provide the necessary price certainty to satisfy both investors and financers.

Figure 6: Pricing Approaches Impact Matrix for Distributed Solar

$/kWh	Resource Cost Approach	RER Factor (Feb,2016)	Avoided Cost Approach	Social Value Approach
Resource Cost Approach	$0.000	-$0.008	-$0.002	-$0.002
RER Factor (Feb,2016)	**$0.008**	$0.000	$0.006	$0.006
Avoided Cost Approach	$0.002	-$0.006	$0.000	$0.000
Social Value Approach	$0.002	-$0.006	$0.000	$0.000

Figure 6 above displays the relative impact of the compensation approaches on electricity prices. For example, relative to the RER purchase price arrangement for the month of February, 2016 ($0.210 per kWh), the purchase of energy from distributed solar suppliers using the Resource Cost pricing ($0.378 per kWh) would increase electricity prices for a total installed capacity of 20 MW renewables by an estimated $0.008 per kWh or 2.4% for residential customers. Similarly, the impact of the Avoided Cost and Social Value approaches is calculated at $0.006 per kWh (1.9%).

Other Pricing Considerations

Billing Arrangements

BLPC recommends that the "Buy All/Sell All" billing arrangement be used as the mechanism for billing all distributed RE suppliers. BLPC anticipates that the opportunity for RE developers to obtain long-term contracts at the rates recommended will increase the attractiveness of RE generation adoption. The maintenance of a safe and reliable electricity supply will prove more challenging for BLPC if the "Sale of Excess" billing arrangement continues under the proposed long-term pricing arrangement. A substantial portion of the mostly fixed generation, distribution and transmission costs are recovered through the volumetric energy charges. Billing under the "Sale of Excess" arrangement would translate into reduced units being billed and therefore result in lower revenues to cover the costs to maintain an efficient grid. The additional financial costs to ensure grid reliability given the increased penetration of intermittent RE resources may be substantial. Customers under the "Sale of Excess" arrangement will not be making an equitable contribution towards the additional costs they generate. These customers would be receiving all the benefits of being connected to the grid, consuming and selling power at their convenience, while contributing little or nothing toward the cost of keeping the network available and reliable. BLPC recommends that the "Sale of Excess" billing arrangement should be ultimately discontinued for all customers with the implementation of future RE rates. To ensure that all customers contribute their fair share, given the benefits they obtain from the grid, all RE customers accepting long-term contracts should be billed based on the "Buy All/Sell All" arrangement.

Contract Duration

The contract period for the rates recommended is 20 years but will be limited to BLPC's current franchise which expires in 2028. Each year, an updated tariff would be calculated using current data, and the updated rate schedule would be applicable only to new entrants. Customers who have already entered into the RE tariff in a previous year will not be affected by the annual adjustment.

Payment Differential

Contract rates will be differentiated based on technology type and capacity sizes. The rates developed above relate only to Wind, Solar Photovoltaic and Biomass technologies as they are currently the more popular RE technologies. Appropriate rates will be developed for other technologies when interest is expressed by developers.

Interconnection Costs

Developers will be responsible for all costs necessary to interconnect to the public grid. These costs include but may not be limited to technical studies, transmission & distribution additions & upgrades, administrative and maintenance costs.

APPENDIX A:

Avoided Cost Approach Methodology & Assumptions

Avoided cost is defined by the United States Public Utility Regulatory Policy Act (PURPA) as the fixed and running costs of an electric utility system which can be avoided by obtaining energy or capacity from qualifying proponents such as renewable generators.

The differential revenue avoided cost method was utilized to calculate long-term estimates of RE avoided cost and was modeled in PLEXOS Utility Planning software ™. The main costs considered for the avoided cost calculations included fixed and variable generation costs. The generation fixed costs (capacity) related to capital costs for new generation capacity to be installed over the 25 year planning period and the fixed operation and maintenance costs for these facilities. Variable (energy) costs included fuel costs and variable operation and maintenance costs, which are influenced by the generation dispatch profile.

In the differential revenue requirement method, an optimized least-cost long-term expansion plan without the proponent RE capacity is developed. This plan takes into account existing plant operating characteristics; plant retirement, new candidate plant additions and their operating characteristics, fuel price projections and demand forecasts. The utility's total production cost is calculated using the input assumptions (see Figure 7 through to Figure 13) to derive the system capital cost, fuel cost, fixed and variable operating costs. The model then assumes that a block of RE capacity operating with given characteristics is available as candidate plant at zero capital and operating & Maintenance (O&M) cost (free RE resource). A second expansion plan is developed, making use of this "free" resource. This "free" RE capacity alters the utility's need to build new generation capacity and/or alters the optimal generation dispatch profile, and, by extension, alters the utility's overall production cost. For RE technologies that contribute to firm capacity, the additional resource modified the least cost expansion plan, however for technologies that are not firm, the additional resource does not modify the expansion plan but only changes the optimal dispatch to include the renewable resource.

The difference in net present value of the total generation costs between the first and second expansion plans is the avoided cost for the RE resource. The difference in net present value of the fuel and variable operating and maintenance (VO&M) cost, divided by the net present value of the energy generated by the unit over its years of operation, is the energy component of the avoided cost for the technology. The difference in net present value of the capital and fixed operating and maintenance cost (FO&M), divided by the unit capacity and number of years of operation, and is the capacity component of the avoided cost for the technology. The avoided cost for firm RE technologies would have a capacity and energy component while technologies which are non-firm would only possess an energy component. The avoided cost calculations using the avoided cost differential revenue approach are reported in Figure 7.

Figure 7: Avoided Costs

Technology	Levelized Avoided Cost	
	Capacity Cost BB$/kW/yr	Energy Cost BB$/kWh
Solar photovoltaic	-	$0.342
Wind	-	$0.284
Biomass	$186.5	$0.194

Figure 8: General Assumptions

Component	Assumptions
Discount Rate	10%/year
Average Load Growth	0.6%/year
MIN Spinning Reserve	5MW
MIN capacity Reserve	32%
Technology blocks modeled	10 MW of utility scale of solar PV (non-firm) 15 MW of distributed solar PV(non-firm) 5MW of wind (non-firm) 25 MW of biomass (firm)

Figure 9: Fuel Price Projections ($/mbtu)

Year	HFO	AvJet	Diesel
2016	22.6	40.2	55.3
2017	21.3	40.4	55.5
2018	21.5	40.4	55.6
2019	22.4	41.2	56.7

2020	23.0	42.0	57.8
2021	23.7	43.0	59.2
2022	24.3	44.1	60.7
2023	24.9	45.3	62.4
2024	25.7	46.5	64.0
2025	26.4	47.8	65.7
2026	27.1	49.2	67.7
2027	27.8	50.8	69.9
2028	28.7	52.3	72.0
2029	29.4	53.9	74.2
2030	30.2	55.6	76.5
2031	31.1	57.2	78.7
2032	32.1	58.8	80.9
2033	32.9	60.5	83.3
2034	33.8	62.2	85.7
2035	34.6	63.9	88.0

Source: Adjusted EIA forecast

Figure 10: Existing Plants

Description	Fuel Type	Fixed O&M ($/kWh)	Variable O&M ($/MWh)	Average Maintenance Days	Forced Outage Rate (FoR) (%)
			Spring Garden		
S1	HFO	202.9	11.9	64.0	0.1
S2	HFO	202.9	11.9	64.0	0.1
D10	HFO	136.6	26.8	37.0	0.1
D11	HFO	136.6	26.8	37.0	0.1
D12	HFO	136.6	26.8	37.0	0.1
D13	HFO	136.6	26.8	37.0	0.1
WH01				67	10.8
D14	HFO	93.6	15.0	36.0	0.0
D15	HFO	93.6	15.0	36.0	0.0
WH02				42	5.1
			Seawell		
GT03	Jet A1	51.7	84.1	41.0	0.1
GT04	Jet A1	24.4	63.1	39.0	0.0
GT05	Jet A1	24.4	63.1	39.0	0.0
GT06	Jet A1	24.4	63.1	39.0	0.0
			Garrison		
GT02	Diesel	70.0	78.3	84.0	0.1

Figure 11: Plant Retirement Schedule

Unit	Retirement Date	Comments
GT02	12/31/2021	Delayed from 2016
GT03	12/31/2021	
S1 & S2	12/31/2023	Delayed from 2016
GT04	12/31/2024	
LSD A	12/31/2025	Delayed from 2018
GT05	12/31/2026	
GT06	12/31/2027	
LSD B	12/31/2035	

While BLPC's is currently looking at an option of 60 MW of temporary generation to facilitate the retirement of units S1, S2 and GT02 while other renewables plans are developed, these decisions have not yet been finalized and hence the retirement dates of these units were modeled as shown above to reflect a future with these units.

Figure 12: Fossil Fuel Candidate Plants

Unit	Fuel	Installed Capacity (MW)	Capacity available to model from	Build cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)
Medium Speed Diesel (MSD17)	HFO	17	1/1/2023	2,300	180.9	19.7
Low Speed Diesel (LSD 30)	HFO	30	1/1/2023	2,850	126.1	13.1
Low Speed Diesel (LSD 17)	HFO	17	1/1/2023	2,850	120.7	13.1
Gas Turbine (GT20)	Jet A1	20	1/1/2023	2,480	28.5	70
Gas Turbine (GT30)	Jet A1	30	1/1/2023	2,480	28.5	70

Figure 13: Renewable Generation Candidate Plants

Unit	Installed Capacity (MW)	Max units model can build	Capacity available to model from	Build cost ($/kW)	Fixed O&M- Base ($/kW/year)	Variable O&M ($/MWh)
Biomass	25	1	1/1/2019	10000	275	16.5
PV (Utility scale)	1	20	1/1/2018	4500	65	-
PV (Distributed)	0.5	20	1/1/2017	5500	65	-
Waste to Energy (WTE)	14	1	1/1/2019	26700	1150	19.2
Wind	1	15	1/1/2018	5600	115	-

APPENDIX B:

Resource Cost Approach Methodology & Assumptions

The resource cost approach is simply an evaluation of the levelized cost of energy (LCOE) generated by distributed Solar PV and Wind systems. The LCOE analysis produces a levelized cost per unit of energy that is a proxy for compensation to distributed RE supplier through a power purchase agreement. The LCOE is sufficient for the owner of the RE resource to recover all the costs associated with the system and earn a market rate of return over the assumed economic life of the system. It is the cost incurred to install and maintain the system divided by the energy the system will produce over its lifetime of operation (Eq.1). The numerator in Eq.1 measures the net present value of the costs incurred to construct and operate the RE generation technology.

$$LCOE = \frac{\sum_{t=0}^{L} \frac{C_t}{(1+i)^t}}{\sum_{t=1}^{L} \frac{E_t(1-dr)}{(1+i)^t}} \qquad (Eq.1)$$

The life span of the technology is represented by L, the discount rate is i, $\mathrm{C_t}$ captures the installation and operating costs incurred in time period t. These costs include the costs related to installation, financing, and ongoing operation and maintenance (O&M) costs. Energy output in period t is denoted $\mathrm{E_t}$ and dr is the degradation rate for the RE resource. The quantity of electrical energy produced by the RE generator depends on a host of factors, including latitude, weather and cloud cover, time of year, the installed capacity of the system, and the orientation and tilt of the panels.

Figure **14: Levelized Cost**

	Solar PV		Wind	
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Levelized Tariff ($/kWh)	$0.378	$0.288	$0.298	$0.248
Internal Rate of Return (IRR)	9%	8%	9%	8%
Payback Period (years)	10	5	10	7

The resource cost for a distributed Solar PV and Wind system with installed capacity of 10 kW was modeled using an Excel model and the input assumptions shown in Figure 15 & Figure 16 to calculate the levelized costs shown in Figure 14. We employed a PV and Wind scenario (Scenario 2 & Scenario 4) to evaluate the sensitivity of the levelized costs to governments RE tax allowances.

Figure 15: PV Input Assumptions & Scenarios (Systems Less than 500 kW)

Components	Scenario 1	Scenario 2	Comments/Source
Equipment unit cost ($/Watt)	$5.5	$5.5	Survey of local PV installers
O&M ($/KW)	65	65	2012 IRP
O&M Inflation Rate (%/year)	3%	3%	Recent 4 year average
PV Capacity Factor (%/year)	18%	18%	Factor utilized in 2012 IRP
Performance Degradation Rate (%/year)	0.5%	0.5%	National Renewable Energy Laboratory estimate. http://www.nrel.gov/
Replace Inverter in Year	15	15	National Renewable Energy Laboratory estimate. http://www.nrel.gov/
Replacement Inverter Cost ($/KW)	600	600	Survey of local PV installers
Length of tariff contract (years)	20	20	BLPC estimate
Percentage System Financed (%)	60%	60%	BLPC estimate
Loan term (years)	20	20	Survey of local financial institutions
Interest rate on loan (%/year)	7%	7%	Survey of local financial institutions
Discount Rate (%/year)	10%	10%	2012 IRP
Maximum Investment Tax Credit	-	$16,500	income tax rate of 33% maximum allowance of $10,000 over 5 years

Figure 16: Wind Input Assumptions & Scenarios (Systems Less than 500 kW)

Components	Scenario 3	Scenario 4	Comments/Source
Equipment unit cost ($/Watt)	$7.5	$7.5	Internet Survey
O&M ($/KW)	115	115	2012 IRP
O&M Inflation Rate (%/year)	3%	3%	Recent 4 year average
Wind Capacity Factor (%/year)	32%	32%	Factor utilized in 2012 IRP
Performance Degradation Rate (%/year)	0.5%	0.5%	National Renewable Energy Laboratory estimate. http://www.nrel.gov/
Length of tariff contract (years)	20	20	BLPC estimate
Percentage System Financed (%)	60%	60%	BLPC estimate
Loan term (years)	20	20	Survey of local financial institutions
Interest rate on loan (%/year)	7%	7%	Survey of local financial institutions
Discount Rate (%/year)	10%	10%	2012 IRP
Maximum Investment Tax Credit	-	$16,500	income tax rate of 33% maximum allowance of $10,000 over 5 years

APPENDIX C:

Social Value Approach Methodology & Assumptions

The Social Value analysis adopted a variation of the methodology implemented by Minnesota Department of Commerce in valuing distributed Solar to the electric network. The US state of Minnesota was a pioneer in incorporating the costs and benefits of distributed PV (DPV) in to ratemaking. In association with Clean Power Research, Minnesota developed a methodology for calculating the value of distributed PV that included social and economic value estimates; we also extended this methodology valuing Wind resources. The choice of value components are influenced by the mix of generation, investments plans, and market structure characteristics. The DPV components we considered relevant to our valuation analysis relates to the avoidance of system losses, variable O&M costs, capacity cost, foreign exchange and environmental benefits. These attributes are examined to provide an estimate of the value of Distributed PV and Wind.

Our valuation analysis relied heavily on data obtained from BLPC's 2012 Integrated Resource Plan published in 2014, supplemented by data from other economic sources. The analysis assumed a total installed capacity of 20 MW or approximately 13% of BLPC's peak load in 2015. This assumption represents the current Cap of 20MW of totaled installed capacity approved by the regulator for distributed renewables and signified a moderate long-term penetration level. Distributed Renewable Generation (DRG) resource degradation is assumed to be 0.5% per year, indicating that the output of the system will degrade over time. RE resources were considered long-term resources for the grid with an expected useful life of at least 20 years. The benefits and costs avoided by PV and Wind are therefore levelized over a 20 year period using a 10% per year discount rate to determine the long-term value of distributed PV to the grid. The procedure and assumptions utilized in monetizing DRG value outlined below is focused on solar PV valuation, however a similar approach was undertaken for valuing Wind resources.

System Losses Savings

System losses represent the amounts of electricity injected into the transmission and distribution grid that are not paid for by consumers. Total losses have a technical and non-technical component. Technical losses are of primary concern in our analysis because it measures the value of additional energy generated by BLPC's generating plants that is lost due to inherent electrical resistance (heat losses) in delivering energy to customers. The value of system losses is the energy loss avoided by consuming power in close proximity to the point of production, as opposed to that resulting from the need to transmit over long distances from BLPC's central generating facility to the customer. The average system losses of 6.9% reported by BLPC for 2015 are utilized in our analysis as the measure for losses avoided by DRG. It is possible that the use of the utility's total system losses may overestimate the loss savings benefits. This is because BLPC reporting of total system losses also includes non-technical losses which are caused by factors outside of the power system such as electricity theft. Non-technical losses are not anticipated to be influenced by distributed RG and ideally should be excluded from the loss savings benefits. However, because no published estimates for non-technical losses exist and the size of total system losses are not considered high by international standards, we assumed non-technical losses to be trivial for the purpose of this analysis and thus considered losses avoided by DRG to be equivalent to that of BLPC's total system losses.

Foreign Exchange Benefits

Foreign exchange value is created when DRG generates energy (kWh) that displaces the need to produce energy from conventional fossil fuel generation. There are three components to the foreign exchange value: the amount of foreign exchange saved by the DRG resource; the amount of foreign exchange used to obtain the DRG resource; and the cost to obtain the foreign exchange. The amount of foreign exchange saved is equivalent to the fuel costs avoided by utilizing DRG to produce the energy. We assume that the DRG resource will displace generation from BLPC's gas turbine units during the on-peak period. BLPC's 2012 integrated resource plan highlights the utility's marginal source of generation are principally gas turbine units that run on diesel and AvJet fuels. In the case of PV we calculate the avoided fuel cost (AFC_i) in year i as per Eq.(2) where UFC_i is the fuel cost of the marginal unit measured in \$ per MMBtu and UHR_i is its heat rate measured in Btu per kWh.

$$AFC_i = \frac{UFC_i * UHR_i}{10^6} \qquad (Eq.2)$$

The estimation of the avoided fuel cost relied on the development of a long-term forecast of the cost of fuels necessary for the operation of the marginal gas turbine plants. These projections were derived from US Energy Information Administration (EIA) database for diesel and AvJet fuels with adjustments for transportation costs and margins. A weighted average heat rate of 12,143 per Btu/kWh was utilized to estimate the gas turbine plant efficiency with a heat rate degradation of 0.1% annually. The foreign exchange saved (FXS_i) is calculated as the product of the avoided fuel cost (AFC_i) and energy supplied by the DPV generator (PVG_i).

$$FXS_i = (AFC_i * PVG_i) \qquad (Eq.3)$$

The cost of PV to the island is principally the loss of foreign exchange from the purchase of the technology and the cost of acquiring the foreign exchange. To estimate the amount of foreign exchange used to obtain the PV resource we adjusted the installed solar photovoltaic cost of $5.5 per watt obtained from a survey of local solar photovoltaic retailers for the local value added content. Eq.(4) shows the calculation of the foreign exchange utilized as the product of the installed PV capacity on the network (PVC_i), the installed price of PV less the local contribution towards the installed price (LVA) .

$$FXE_i = PVC_i * PVP_i * (1 - LVA) \qquad (Eq.4)$$

The net foreign exchange benefit (NFX_i) is derived in Eq.(5), where FXS_i is the foreign exchange savings, FXU_i is the foreign exchange expenditure and IC is the cost of foreign exchange. An interest rate on sovereign foreign debt of 5.3% (three year average) was used as the shadow price for the cost of foreign exchange within the economy.

$$NFX_i = (FXS_i - FXE_i) * (1 + IC) \qquad (Eq.5)$$

$$LNFX = \frac{\sum_{i=1}^{20} \frac{NFX_i}{(1+r)^i}}{\sum_{i=1}^{25} \frac{PVG_i}{(1+r)^i}} \qquad (Eq.6)$$

The levelized foreign exchange value ($LNFX$) shown Eq.(6) is calculated as the sum of the discounted net foreign exchange benefit divided by the sum of the discounted energy output of PV. The levelized foreign exchange benefit after adjustments for system losses is calculated at $0.165 per kWh.

Avoided Variable O&M Cost

Operation and maintenance costs are avoided when the DRG avoid the need to generate energy using BLPC's generation. The variable O&M costs for marginal gas turbine plants were derived from the 2012 IRP as $0.05 per kWh and escalated annually to account for inflation. The avoided O&M is the product of the unit O&M cost of the marginal unit ($O\&M$) and the per unit DPV production (DPV_i) as per Eq.(7) .

$$O\&M_i = (O\&M * DPV_i) \qquad (Eq. 7)$$

The discounted avoided O&M cost is divided by the discounted DPV output and adjusted for system losses following a similar procedure in Eq.(6) to derive the levelized avoided variable O&M cost of $0.061 per kWh.

Avoided Generation Capacity

Generation capacity value is the amount of system generation capacity that can be deferred or avoided due to the installation of DRG. The 2012 IRP report indicated that no additional generation capacity was required until 2017. DRG can however hedge against events that could accelerate the need for additional centralized generation capacity such as the loss of existing resources due to technical issues or the unexpected increase in demand driven by economic recovery. Gas turbines have been identified by the 2012 IRP as the source of new utility scale peaking capacity and are anticipated to be the long-term peaking capacity that DPV avoids. The 2012 IRP reported a capital cost of $2,480 per kW for the new peaking plant addition with a heat rate of 10,353 per Btu/kWh. The avoided capacity value is derived by amortizing the capital cost of the new plant addition over its expected life. The total discounted amortized capital cost is divided by the discounted energy produced by DPV, similar to Eq.(6) and the avoided generation capacity costs are derived. The capacity cost of DPV needs to account for the ability of DPV to contribute to the total system capacity without compromising the reliability of the network. GE Energy Consulting (GE) in an intermittent penetration study conducted on the island calculated a capacity contribution of 40% for DPV at a penetration level of 15 MW. The avoided generation capacity cost is multiplied by DPV capacity contribution of 40% to yield a levelized capacity value of $0.0001 per kWh.

Environmental Benefit

The environmental benefits of DPV relates to its potential to reduce carbon emissions and mitigating heath and ecosystem damage potentially caused by climate change. Carbon reduction benefits are the amount of carbon displaced times the cost of reducing a ton of carbon. The amount of carbon avoided is directly linked to the amount of energy displaced, and the carbon intensity of the fossil fuel generator's output being avoided. The initial step in calculating the environmental benefits is to determine the annual physical units of avoided emissions by DPV as compared to the marginal diesel and AvJet fuels fired units for electricity generation. The CO_2 emission rate of 162 pounds/million BTU for the gas turbine plants obtained from the US Energy Information Administration was assumed to be the avoided emission rate for the marginal plants. The US Environmental Protection Agency (EPA) social cost of carbon estimates for the United Sates was assumed for Barbados because no estimates exist for the island. The EPA social cost calculation is a measure of the economic damage associated with an increase in carbon dioxide emissions. Given the observation that island markets such as ours are more vulnerable to the negative effects of climate change, EPA social cost estimates may underestimate the economic damage of carbon emissions on the island. The EPA social cost estimates are converted to cost per unit fuel consumption using the emission rate of 162 pounds/million BTU. We calculate the environmental benefits (EB_i) in year i as per Eq.(8) below where SVC_i is the social environmental cost measured in $ per MMBtu and UHR_i is its heat rate of the marginal unit measured in Btu per kWh.

$$EB_i = \frac{SEC_i * UHR_i}{10^6} \qquad (Eq. 8)$$

The total environmental benefit is the product of the unit environmental costs and the per unit DPV production. Again as per Eq.(6) the discounted environmental benefit is divided by the discounted DPV energy output, after an adjustment for system losses the levelized environmental benefit was calculated as $0.115 per kWh.

Social Value Results

The methodology outlined above was also utilize in calculating the social value of Wind towards the avoidance of system losses, operations & maintenance costs, generation capacity costs, environmental costs and foreign exchange savings. The calculated value for each component in our analysis was summed to yield a levelized value of PV of $0.341 per kWh and Wind of $0.254 per kWh (Figure 17).

Figure 17: Levelized Social Value

Value Components	**PV Value $/kWh**	**Wind Value $/kWh**
Foreign Exchange Benefit	$0.1649	$0.1239
Avoided Plant Variable O&M	$0.0607	$0.0298
Avoided Generation Capacity	$0.0001	$0.0001
Environmental Benefit	$0.1151	$0.1007
Levelized Value ($/kWh)	$0.3408	$0.2543

Figure 18:Solar Photovoltaic Assumptions

Component	Assumptions
Capacity	20 MW
Capacity Factors	18%
Load Carrying Capacity	40%
Cost escalator	2% /year
Degradation Factor	0.5% /year
Discount Rate	10%
Fixed Operating & Maintenance Expense	$65/KW/year
Installed Cost	$5.5 /watt

Figure 19: Wind Assumptions

Component	Assumptions
Capacity	20 MW
Capacity Factors	32%
Load Carrying Capacity	28%
Cost escalator	2%/year
Degradation Factor	0.5%/year
Discount Rate	10%
Fixed Operating & Maintenance Expense	$115/KW/year
Installed Cost	$7.5 /watt

Figure 20: Marginal Unit Assumptions

Component	Assumptions
Margin units	Gas turbines
Heat Rate	12,143 Btu/kWh
Heat Rate Degradation Factor	0.1%/ year
Variable O&M Cost	US$0.05/kWh
Inflation rate	2% /year

Figure 21: Candidate Plant Assumptions

Component	Assumptions
Unit	Gas turbine
Heat Rate	10,353 /Btu/kWh
Capital Cost	$2,262 /KW

Figure 22: Weighted Fuel Cost Avoided ($/MMBTU)

Year	PV	Wind
2016	34.4	24.8
2017	34.2	23.8
2018	34.3	23.9
2019	35.1	24.9
2020	35.8	25.4
2021	36.7	26.2
2022	37.7	26.9
2023	38.7	27.6
2024	39.7	28.3
2025	40.8	29.1
2026	42.0	29.9
2027	43.3	30.8
2028	44.7	31.7
2029	46.0	32.6
2030	47.3	33.5
2031	48.7	34.5
2032	50.1	35.5
2033	51.6	36.4
2034	53.0	37.5
2035	54.4	38.4