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# Regulatory Audit of the Barbados Light &Power Co. Ltd.

## Final Report



[redacted]

**Prepared for the Fair Trading Commission of Barbados**

NERA
Economic Consulting

MMC Marsh & McLennan Companies

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## Executive Summary

The Fair Trading Commission of Barbados (FTC) engaged NERA Economic Consulting (NERA) to undertake a regulatory audit of key aspects of the regulatory accounting policies and rates of Barbados Light & Power Company, Ltd. (BL&P). Our assignment included nine major tasks:

1. Prepare an embedded cost study and compare the results to the class revenue allocations and rate design in current rates.
2. Prepare a time-differentiated marginal cost study and compare the results to the class revenue allocations and rate design in current rates.
3. Review and comment on BL&P's accounting policies related to definition of rate base, in light of policies in use in the US and Europe.
4. Calculate the annual rate of return on rate base that BL&P has earned over the period 2002-2005, compared to the rate of return authorized in the last rate case (1983).
5. Recommend class revenue allocations and rate structures for each class, given current economic conditions in Barbados.
6. Assess the appropriateness and feasibility of time-of-use (TOU) rates in Barbados.
7. Assess the appropriateness of BL&P's methods and tools for forecasting load and planning system expansion.
8. Review and comment on FTC staff's report on incentive-based regulation.
9. Provide training to FTC staff on these topics.

This Interim Report summarizes the preliminary results from tasks 1-7.[1]

### Revenue Requirement Policies

Based on a limited financial and regulatory review, we made a number of findings on BL&P's rate-base-associated accounting policies and earned rates of return. Reproduction Cost New (RCN), a form of "fair value" regulation, used in the 1983 rate case to value electric utility rate base has significant disadvantages. *We recommend that the FTC shift to use of actual, verifiable,*

[1] The NERA team provided separate written and oral comments to FTC on the FTC staff's draft report on Incentive-Based Regulation. The team also provided informal training during their on-site work and a formal training session at the end of the project.

and prudently-incurred historic costs to value rate base. This approach treats both customers and utility investors fairly.

The Company's other accounting policies appear to be generally reasonable from the standpoint of regulatory accounting and finance.[2] However, we recommend that the FTC investigate and approve new depreciation rates for the Company. This review would not necessarily require a rate case. We also suggest that the Company and the Commission consider including an equity return on plant under construction; i.e., use the weighted-average cost of capital (WACC) to capitalizing the cost of financing plant under construction.

Utility rates are set based on a test year and the utility may in fact earn more or less than its allowed return on equity between rate cases. Regulation should not strip a utility of the incentive to strive to earn more than its allowed return if it can find ways to improve its operating efficiency. Nevertheless, regulators periodically review a Company's earnings as one way to evaluate whether or not the utility's rates are set too high or too low.

NERA performed a limited financial review of BL&P's earnings for 2002-2005 and compared the returns on equity earned in those years to the rate implicitly authorized in the 1983 rate case. For consistency with the policies in effect in 1983, we used the Company's PUB-approved depreciation rates and the RCN rate base.[3] BL&P earned more than the allowed rate of return authorized in 1983 in 2003 and 2004, but less in 2002 and 2005.

We also analyzed the Company's earnings in 2002-2005 using BL&P's preferred depreciation rates and historic cost rate base. The earned rates of return on equity range from 7.83 percent (in 2005) to 14.86 percent.

Based on available information, if a rate case were held today, a reasonable allowed return on equity for BL&P using historic cost for rate base and the Company's preferred depreciation rates would be 11.90 percent and a fair overall rate of return (WACC) would be 10.40 percent. The cost of equity is based on an analysis of a group of comparable US utilities plus a country risk premium of 1.35 percent to compensate the Company's shareholders for the greater risk of investing in Barbados. These estimated market rates are above the rates earned by BL&P in 2005. We recommend that in BL&P's next rate case, a market-based return on equity be estimated, using an approach which averages the calculated cost of equity capital for a sample of

[2] NERA has not performed an evaluation of the reasonableness of the Company's accounting practices for financial reporting purposes. Rather, NERA has focused on how the accounting and financial information reviewed should be treated for regulatory purposes.

[3] While we are recommending that the Commission use historic cost as the measure of fair value in future rate cases, it would be inconsistent to use historic costs when comparing BL&P's historical earnings to allowed rates of return established on another basis.

*comparable US utilities computed using both the CAPM and DCF methods, and adjusts for the* country risk premium for Barbados.

Using the RCN rate base and PUB-approved depreciation rates, and adjusting for expected inflation (2.7 percent) to avoid double-counting,[4] we estimated a real WACC and cost of equity of 7.49 and 8.96 percent respectively, compared to BL&P's 2005 earned returns of 7.12 and 7.79 percent. However, these results must be taken cautiously, as the real WACC and cost of equity are very sensitive to the inflation rate used in the calculation.

BL&P's capital structure has a higher share of equity than most utilities in the region. Using a lower share of equity to calculate allowed rate of return would produce a lower revenue requirement. At a minimum, we recommend that the Commission scrutinize carefully the reasonableness of the Company's capital structure in a future rate case. Whether the Commission uses the Company's actual capital structure or imposes a hypothetical one in a future rate case, the determination of an appropriate capital structure should reflect the capital structure that would be reasonable for ratemaking purposes.[5]

## Class Revenue Allocations

In practice, whether class revenue allocation is based on embedded or marginal costs, other rate objectives typically influence class revenue allocations. For example, the cost studies may suggest that Class 1 should receive a 40-percent increase in revenue allocation, while Class 2 should receive a 20 reduction. In most jurisdictions, these cost-justified adjustments would be phased in over several rate cases (or rate adjustments), rather than implemented all at once.

In this project we calculated both class embedded costs (based on a 2005 test year) and 2006 class marginal cost revenues (based on 2005 consumption levels).[6] The embedded study used the historical cost definition of rate base and depreciation. It shows that at current rate levels (which produce an overall rate of return on investment of 6.5 percent), class rates of return vary significantly. An allocation of total revenue requirement based on embedded costs would produce the same rate of return for each class. The current rates of return by class and the rate changes necessary to yield a 6.5-percent rate of return from each class are shown below.

[4] For consistency with the US-based nominal rates of return, we used the average of the US inflation rate forecast (Production Price Index) in 2006 and 2007 as the estimate of expected inflation. Source: "Blue Chip Econometric Detail. Supplement to Blue Chip Economic Indicators. Vol. 22. March 10, 2006.

[5] The Commission should keep in mind that imposing a capital structure that sharply diverges from its actual capital structure would hurt the Company's ability to raise funds from the capital markets. This may result in underinvestment in critical infrastructure required to provide safe, reliable and efficient utility services to its customers.

[6] The full embedded cost study is located in Appendix B to this report. The full marginal cost study is located in Appendix C.

**Table 1 – Current Class Rates of Return according to ECOSS and Rate Changes Necessary to Produce Equal 6.54-Percent Rates of Return by Class**

| Rate Class | RORs Currently Earned By Customer Class | Tariff Changes Required to collect same ROR by class |
|---|---|---|
| Domestic | -1.32% | 17.48% |
| Employees | -5.22% | 28.62% |
| General | 8.42% | -3.02% |
| S.V.P. | 11.29% | -7.67% |
| LP | 15.79% | -12.51% |
| Street Lighting | -15.64% | 52.62% |
| Overall | 6.54% | 0.00% |

The embedded study also indicates that, to produce an overall return equal to NERA's estimates of BL&P's current cost of capital of 10.40 percent, is required an overall tariff increase (including fuel) of about $30 million or 9.0 percent.

The marginal cost study provides estimates of the marginal cost of each element of service, time-differentiated for elements with costs that vary with time, and by customer class. Marginal cost revenues were computed by multiplying the 2006 marginal cost of each element of service by estimates of the corresponding units for each class. For purposes of economic efficiency, each class (and ideally each customer) should pay revenues sufficient to cover, at a minimum, its marginal cost of service.

**Table 2** below shows the rate changes necessary for each class to produce a 10.40% rate of return, according to the ECOS study, and compares them with the changes by class required if each class were to pay an equal percentage of its marginal cost of service (Equi-Proportional Marginal Cost or "EPMC").

**Table 2. Comparison of Rate Changes Required under the EPMC Approach and the ECOSS Revenue Allocation, to Meet Overall 10.40% ROR**

| | Rate Change Required to Match EPMC Class Revenue at 10.40% ROR | Rate Change Required to Match ECOSS Class Revenue at 10.40% ROR |
|---|---|---|
| Domestic Service | 37.4% | 34.7% |
| Employee | 79.0% | 50.7% |
| General Service | 21.3% | 4.3% |
| Secondary Voltage Power | -2.6% | -1.9% |
| Large power | -11.5% | -9.7% |
| Street Lights | -13.7% | 82.3% |
| **Average Rate Change** | **9.0%** | **9.0%** |

Our preliminary estimates of BL&P's current cost of capital suggest that a significant overall rate increase may be warranted. However, our review did not cover other elements of the revenue requirement. We recommend that until a full rate case is conducted, any adjustments to class revenue allocations (such as those that might be undertaken in a revenue neutral rate adjustment) be conservative.

It is clear, though, that whether the benchmark is embedded costs at today's rate of return, embedded costs at BL&P's current estimated cost of capital, marginal cost revenues, or EPMC revenues, rates for domestic customers and employees are significantly below cost, and rates for SVP and LP customers are above cost. We recommend that when rates are changed, a transition period to move these class' revenues to more appropriate levels be considered. We also recommend that FTC begin a public information program to educate stakeholders about the importance of and need for rate restructuring, and to prepare customers for the rate changes that are likely to be required.

## Rate Structures

Current rate structures for most customer classes do not reflect the underlying structure of cost of service. Restructuring rates would provide more efficient price signals to guide customer decisions on use of existing appliances, choice of new electricity-using and electricity-saving equipment, and investment in self-generation.

We recommend that electricity rate structures for Barbados be developed by starting with the structure of marginal costs, and then making adjustments necessary to achieve other objectives, including customer understanding and feasibility of implementation. Use of marginal cost information is particularly important when TOU rates are being developed, because marginal cost information is necessary to design seasonal and peak/off-peak price differentials that will help consumers make efficient decisions about whether to shift load from peak to off-peak, and whether to invest in new practices or equipment that will allow them to reduce consumption in high cost periods or increase consumption in low cost periods. A marginal cost-based rate structure is also important when consumers are considering whether to invest in self-generation that will require backup by the utility. Our specific rate structure recommendations are as follows:

Domestic and BL&P Employees:

Under current domestic rates the most revenues are collected in the base energy kWh charge and the fuel adjustment charge. The marginal cost study shows that local distribution facilities and customer cost make up a significant portion of the domestic costs. The efficiency and fairness of the domestic rate structure would be improved by introducing:

- a *customer charge,* that covers marginal customer costs and
- a *facilities charge* per kVA, that covers the marginal cost of local distribution facilities.[7]

Introduction of a facilities charge per kVA of design demand would provide additional revenue stability for BL&P, because less revenue would be dependent on the level of kWh sales. Furthermore, use of a facilities charge is especially important to a utility in a resort area such as BL&P, as it assures year-round contribution to the cost of the distribution network from seasonal customers. If warranted, a lifeline feature could be introduced for low-income families, by reducing or eliminating the two fixed components of the bill.

BL&P Employees currently benefit from a subsidized per-kWh rate. A more efficient mechanism for providing this benefit would be to convert it to a fixed credit on the bill, so that employees would see the same marginal price for kWh use as other domestic customers.

General Service:

The combined efficiency and equity arguments for customer and facilities charges to the domestic customer class also apply to the general service class.

SVP and LP:

The key recommendations for SVP and LP are as follows:

[7] Design demand for domestic customers ranges from less than 1 kVA to approximately 10 kVA, so, although it is a fixed component of the bill for individual customers, the facilities charge would be a small component of the bill for low use customers, who probably tend to be low income as well.

- As is the case for the other classes, incorporating a customer charge and a design demand/contract demand charge in the SVP and LP rates. This would make the rate structures more cost reflective, move the per-kWh recovery toward marginal energy cost, and potentially reduce revenue volatility.

- In SVP and LP rates, the total kWh charges (fuel plus other) are substantially in excess of the marginal energy costs. Given the prevalence of self-generators in Barbados and the risk of uneconomic bypass[8] suggests additional specific recommendations for these classes, particularly, setting demand charges that are higher than marginal capacity cost. Alternatively, a reservation charge for standby customers may be set to recover a portion of embedded capacity cost in excess of marginal capacity costs.[9]

- Although information on the likely responsiveness of BL&P customers to time-of-use (TOU) rates is not currently available, it is highly likely that LP and larger SVP customers would shift enough demand from peak to off-peak hours to justify the additional metering and billing costs associated with implementing TOU rates.[10] The marginal cost study identifies significant differences in marginal energy costs (peak cost is about 50 percent higher than off-peak), and all marginal capacity costs fall in the peak period, defined as 9 am – 3 pm on weekdays.

  BL&P is gradually replacing electro-mechanical meters with electronic meters, which can be configured to provide billing information for TOU rates. Although the current billing system may not be able to handle TOU rates, many utilities use a separate billing system for TOU customers in such situations. Thus, it may be feasible for BL&P to implement TOU rates for its largest customers in the near term.

Optional interruptible rate for self-generators and other large customers

Higher demand charges for self-generators may create a demand for optional interruptible rates. Self-generators willing to take backup service on an interruptible basis, could pay lower demand charges to compensate for their willingness to have service curtailed in hours when capacity is constrained. Such interruptible arrangements should include a several-year-long contract to keep customers from shifting on and off the interruptible rate as BL&P's reserve margin changes. Other large customers might be interested in an interruptible option for a portion of their loads as well.

[8] Uneconomic bypass results when customers choose an alternative supply of electricity (such as installing self-generation) that has a higher cost than the utility's true economic (marginal) cost of providing the same service.

[9] High fuel prices or fuel supply disruptions could affect all these units, meaning that most customers with self-generation would need backup at the same time.

[10] For example, we understand that the Water Authority, a major BL&P customer, is currently considering a major renovation of its facilities. Faced with TOU rates, the Water Authority might redesign its system so that it can pump off peak, thereby saving its own customers money on their water bills and freeing up BL&P capacity to serve other electricity customers in the peak period.

## Demand Forecasting and System Planning

One of our tasks in this project was to assess the appropriateness of BL&P's methods and tools for forecasting load and planning system expansion. We based our analysis on a brief written summary of methods, prepared by BL&P, and discussions with company engineers.[11] Our impression is that BL&P is using appropriate methods for both demand forecasting and system planning, although additional quantitative risk and options analysis might be useful. Specific recommendations are summarized below.

### Demand Forecasting

The method of demand forecasting employed by BL&P is a simple extrapolation of historical levels of demand growth.[12] Given the context of a small system with peak load of around 150 MW, with load growth of the levels described, and given the economic new generator size of between 20 MW and 30 MW, NERA is of the opinion that the simple extrapolation method of forecasting load growth is appropriate for BL&P for purposes of generation planning.

Regarding the impact of load forecast error on generation planning decisions, we expect that the small absolute values of load growth relative to the economic size of an efficient new unit means that load forecast error, and the simplified method of forecasting load in particular, should have a relatively low impact on the ability of BL&P to maintain generation adequacy. We base this conclusion on a comparison of the level of load growth, and the uncertainty around that level, to the economic new generator size.

We recommend that any significant and non-typical load additions be reflected with a "bottom-up" adjustment to the simple forecast. For example, any exceptional one-off addition or withdrawal of an energy-intensive industry would justify a one-off adjustment to the simple extrapolation of historical load growth.

### System Planning

NERA has conducted a limited review of the generation expansion process performed by BL&P and we conclude that the relevant planning criteria, relevant parameters, and relevant decision variables are taken into consideration in that process. We have not tested the robustness of solutions obtained; however, we note that BL&P identifies solution robustness as a key criterion.

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[11] "Barbados Light & Power Company Limited - System Expansion Planning," March 8, 2006.

[12] A base case level of demand growth of 4 percent of peak load per year is used in it most recent forecast, with low and high cases of 2 percent and 6 percent respectively.

We note that BL&P states that "risk is not explicitly dealt with in the 'least cost' planning process". However "Risk is introduced in the planning process by using Monte Carlo models to represent the various uncertainties (fuel prices, technological obsolescence, etc)"[13] and that the company does have access to Monte Carlo models such as @Risk and Crystal Ball.

NERA recommends that BL&P investigate the expanded use of these models. Developing the system expansion plan in a probabilistic manner would calculate the least cost associated with an LOLP target within a single integrated model run, in which the LOLP associated with a particular generation configuration was also calculated. This model would probabilistically estimate the LOLP and VOLL associated with each candidate expansion plan by Monte Carlo analysis, together with the expected cost – and the range around that expected cost – associated with each candidate expansion plan.

We understand that BL&P ignores the impact of fuel taxes in its system planning process. Because the pre-tax cost of imported fuels is the true cost to the economy of Barbados, this BL&P policy means that the objective of generation planning is to minimize costs to the country, not necessarily to minimize costs to the Company. We believe that this is a socially-responsible approach.

We also understand that the target level of reliability (24 hours per year) used by BL&P has not been reviewed in many years. As customer use of electricity changes (*e.g.*, use of electronic equipment that is sensitive to outages) and the cost of adding reserves changes over time, VOLL and the optimal LOLP can also change. We recommend that BL&P undertake a new analysis to verify that this reliability target still represents the least-cost trade-off between the cost of unserved energy and the total cost of energy production.

[13] Quotations are from "Barbados Light & Power Company Limited - System Expansion Planning," March 8, 2006.

# I. Introduction

The performance of the electricity sector is crucial to the overall performance of any economy. This is especially the case for an isolated economy with limited indigenous fuel resources. Sector efficiency requires cost reflective rates to provide efficient price signals to consumers, as well as regulatory policies that induce the utility to operate and expand the system in an efficient manner. At the same time, the regulator must balance impacts on customers, utility shareholders, the environment, and economic development.

To attain the goal of efficiency, with due consideration to societal concerns, the regulator requires a thorough understanding of the regulated company's systems, processes and costs, as well as the links between them. The systems, processes and costs cannot be understood in isolation; for example:

- The company's rate base, and consequently the return earned on rate base, depends on accounting policies related to capitalization of expenditures, and depreciation.
- The fairness and efficiency of the allocation of total revenue requirement to various classes of consumers is enhanced when total costs are carefully unbundled, cost causation is determined, and the allocation scheme takes into consideration the time patterns of each class' consumption and the incremental costs of providing service in each period.
- The appropriateness of the current rate structure depends not only on the historical cost as found on the company's books, but also on the expected cost of new generation, transmission and distribution resources, and the time patterns in which they are used.
- The models used to project demand growth help to establish the need for, and expected costs of, system expansion. Expansion costs and expected loads in turn influence the level of average rates and the appropriate rate structures.
- The feasibility of time-of-use rates depends on factors such as the costs of advanced metering, customer response to time-varying rates, and on variations in the incremental costs of providing service from the generation, transmission and distribution systems.
- Incentive mechanisms (such as the rules for cost recovery allowed under a fuel adjustment charge) may be established to provide incentives for efficient and environmentally responsible planning and use of alternative fuels and generation resources.

Recognizing these linkages, the Fair Trading Commission of Barbados (FTC) engaged NERA Economic Consulting to undertake a regulatory audit of key aspects of the regulatory accounting policies and rates of Barbados Light & Power Company, Ltd. (BL&P). Our assignment included nine major tasks:

1. Prepare an embedded cost study and compare the results to the class revenue allocations and rate design in current rates.

2. Prepare a time-differentiated marginal cost study and compare the results to the class revenue allocations and rate design in current rates.

3. Review and comment on BL&P's accounting policies related to definition of rate base, in light of policies in use in the US and Europe.

4. Calculate the annual rate of return on rate base that BL&P has earned over the period 2002-2005, compared to the rate of return authorized in the last rate case (1983).

5. Recommend class revenue allocations and rate structures for each class, given current economic conditions in Barbados.

6. Assess the appropriateness and feasibility of time-of-use (TOU) rates in Barbados.

7. Assess the appropriateness of BL&P's methods and tools for forecasting load and planning system expansion.

8. Review and comment on FTC staff's report on incentive-based regulation.

9. Provide training to FTC staff on these topics.

This Interim Report summarizes the preliminary results from tasks 1-7.[14] Section III discusses electricity rate concerns and Section IV summarizes rate objectives identified during our visits to Barbados. The remainder of this report is organized in four major sections. Section V deals with policies related to the total revenue requirement. Section VI deals with the allocation of the total revenue requirement to the individual customer classes. Section VII addresses rate design for each customer class. Section VIII provides our review of BL&P's load forecasting and system expansion approaches. The full texts of the preliminary embedded cost and marginal cost studies are located in Appendices B and C respectively.

It is important to emphasize that the analysis undertaken for this report is not sufficient support for a rate case. Our terms of reference did not include a complete analysis of the components of BL&P's revenue requirement. Furthermore, our cost study results are based on available information, some of which is outdated, and should be supplemented with more up-to-date and comprehensive data before rates are set. Finally, any major rate restructuring requires detailed

[14] The NERA team provided separate written and oral comments on the FTC staff's draft report on Incentive-Based Regulation. The team also provided informal training during their on-site work and a formal training session at the end of the project.

studies of likely impacts on customer bills, consumption levels and patterns, utility costs, and utility revenues.

## II. Rate Concerns in Barbados

We began the assignment by holding discussions with FTC and BL&P staff to identify rate-related concerns. Several concerns were raised.

BL&P has not had a rate case since 1983, although changes in fuel costs have been passed through to consumers through the fuel cost adjustment. There is a general concern that the class revenue allocation and rate structures no longer reflect BL&P's cost structure. In particular, demand charges are low, which reduces the incentive for customers to improve their load factors.[15]

Barbados, with its dependence on imported fuel, has been hard hit by increases in oil and gas prices. Because BL&P's fuel costs are passed through to consumers in the fuel adjustment, customers of all types are complaining about high electricity bills. The Government of Barbados has also been affected by the increased fuel prices. In particular, the price increases have affected the country's foreign exchange outflow.

As a result of rising electricity prices, manufacturers in Barbados are finding it difficult to compete with competitors, such as those in Trinidad and Tobago, where electricity prices have remained low. Manufacturers have been asking for special electricity rates to improve their competitiveness, and to improve their ability to expand and create more employment. BL&P's largest industrial customers are in the sugar, rum and food processing industries. The Barbados Water Authority uses 8-10 percent of BL&P's energy sales to pump water.

To reduce their electricity bills, some manufacturers have installed their own (relatively inefficient) diesel generators, which allow them to take advantage of the zero excise tax on the price of diesel fuel.[16] Self-generators avoid paying VAT that would be added to their bills for electricity purchased from BL&P. The tax-driven incentives to invest in self-generation may not be optimal from the point of view of the country. Furthermore, these customers rely on BL&P for their electricity needs when their generators are out of service. Under current rates they pay relatively low demand charges based on their highest demand in the previous 12 months. It is not clear that they are compensating BL&P for the full cost of standing by to supply their backup needs.

[15] Load factor is the ratio of average hourly demand to peak demand. A customer with a high load factor uses energy at a fairly constant rate, while a customer with a low load factor has a "spikier" load pattern and requires more capacity per kWh consumed.

[16] BL&P also benefits from this tax policy, but the policy distorts the relative price of fuels locally. BL&P plans and dispatches on the basis of world fuel prices, which is optimal for the country, but this results in higher fuel adjustments in consumer's electricity bills than would be the case if BL&P generated more electricity with diesel.

There is growing interest in renewable energy generation in Barbados and discussion of using net metering[17] for energy fed into the grid by such generators. The revenues received by renewable generators using the net metering approach are highly dependent on the rate structure—in particular the portion of the rate that is a per-kWh charge.

In addition to concerns about high electricity prices overall, a number of other concerns about BL&P's rates were also expressed.

- Consumers want rates and rate-setting processes that are transparent.
- Is electricity being used efficiently? Current rates have no time-of-day differences, so there is no incentive to limit consumption in periods when the cost of providing electricity is relatively high.
- Is electricity production the best use of expensive jet fuel?
- Is BL&P adequately investigating renewable generation sources that would reduce the country's dependence on imported fuel?
- Are relative levels of energy and demand charges in current rate cost reflective?
- Are the cross-subsidies in current rates justified? Rates for residential customers are significantly lower than rates for business customers.
- Are seasonal consumers (with vacation homes used only a few months a year) paying their share of BL&P's costs?
- Should the use of historic rate base to set rates, used by the FTC for Cable and Wireless, also be applied to BL&P?
- Would an interruptible rate option make sense in Barbados?

[17] Net metering allows the meter to run backwards when the customer with generation is producing more energy than is being consumed on site. The implicit payment (or credit) to the customer by the utility for this energy is equal to the per-kWh charge in the normal rate times the number of kWh fed into the grid.

## III. Rate Objectives for Barbados

Electricity rate objectives in most countries are the same, although the emphasis placed on the sometimes-competing objectives can be different. Based on our discussions with FTC and BL&P, we have identified the following electricity rate objectives, which influence our recommendations for rate policies in Barbados.

- Minimizing total costs to consumers, for an acceptable quality of service;
- Providing BL&P with sufficient revenue (including a reasonable rate of return) to operate and expand a reliable system;
- Giving consumers efficient price signals about the true cost of electricity service;
- Encouraging efficient investment by consumers in self-generation, load control, and energy conservation;
- Designing rates that are understandable to consumers and feasible for implementation by the utility;
- Avoiding unacceptably large and sudden changes in bills;
- Providing low-income consumers with a minimum amount of affordable electricity.

Most of these objectives require class revenue allocations and rate structures that are based on cost of service. The efficiency objectives require using rate levels and structures that reflect the structure of the marginal or incremental cost of providing the service.

## IV. Revenue Requirement Policies

For private ownership of utilities to be sustainable and serve customers well over the long term, utilities must have a reasonable *opportunity* to recover all of their prudently-incurred costs, including the investor-required cost of capital. While there is no guarantee that a utility will actually be able to earn its cost of capital once rates have been set, if the utility does not have a realistic opportunity to recover its costs, harm to customers will likely result in the long term, if not sooner. At the same time, rates should not be higher than necessary.

BL&P has not filed a rate case since 1983. The FTC, which was established in 2001 and operates under a new law that supersedes the law that governed electric utility regulation in 1983, has asked NERA to conduct a regulatory audit of certain aspects of the operations of BL&P.[18] This task is not a full regulatory audit, of the type that would be needed in a rate case, but instead a review of the following issues:

1. BL&P's policies for defining rate base and associated accounting practices, including:

    a. Policies on revaluation of assets.

    b. Treatment of major new capital investments, including the treatment of assets during construction and the timing of their admission to the asset base.

    c. Rules on capitalization of expenditures, both for repairs and refurbishment.

    d. Depreciation policies, both for financial reporting and, if appropriate, tax purposes.

    e. Retirement of assets and the treatment of any associated write-offs.

    f. Regulatory rules regarding utility investment in non-core activities.

2. The rate of return achieved by the Company in 2002-2005 compared to that which was allowed by the Public Utilities Board (PUB) Decision in 1983.

[18] The Public Utility Board (PUB) was the Regulator during the 1983 BL&P rate case decision.

## A. Rate Base Valuation

Rate-of-return regulation focuses on a utility's costs, which includes both operating and capital costs. Capital costs include a return *of* and *on* the prudently-incurred assets (rate base) that have been installed to provide public service. A utility is entitled to an opportunity to recover its depreciation cost and a fair rate of return on its invested capital. A key question is how to define the value of the rate base.

## B. Alternative Approaches to Valuing Rate Base

There are a number of methods to determine the value of rate base. In BL&P's 1983 rate case, the regulator used a "fair value" approach and defined that fair value as the current cost of rebuilding the existing system—the "reproduction cost new" (RCN) approach. Other fair value rate base methods include replacement cost (the current cost of the system if it were updated to current technology), trended historical cost, and historical cost, among others.[19]

There are two basic methods used by regulators to determine rate base:

1. Modeled rate base approaches, such as RCN, generally define rate base not as the actual, verifiable, and prudent investment, but using some model of the reproduction or replacement cost of the system. The updating of plant costs to current levels results in giving equity stake holders of the utility a greater shield against the risk than they would face in other investments.[20]

2. Historic cost (also known as original cost) approaches value assets based on what a company spent when the assets were acquired, less accumulated depreciation.

In the US, a Supreme Court decision makes clear that there are alternative ways to measure rate base and any method is permissible so long as the "end result" is reasonable.[21] This means that either modeled rate base or historic cost rate base methods can be used in the US, so long as both utility customers and utility investors are treated fairly.

## C. Regulatory Practice on Valuing Rate Base

Most jurisdictions in the US use the original cost approach. The National Association of Regulatory Utility Commissioners (NARUC) reported that for 1992-1993 all states use historic

[19] Historic cost is often used to determine rate base in jurisdictions that use "fair value" rate base methods.

[20] Goodman, Leonard S. The Process of Rate Making. Public Utility Reports, Inc. (Vienna, Virginia, 1998), pp. 770-71.

[21] *See*: Robert Hahne and Gregory Aliff *et. al.* Accounting for Public Utilities. Lexis Nexus (Newark, NJ, 2001), p.2.07[3]; and US Supreme Court, "Federal Power Commission v. Hope Natural Gas Co." (1944), 320 US 591.

cost,[22] with the few exceptions presented in Table 1 below. Table 1 makes clear that those US states that are "fair value" jurisdictions today all rely, at least in part, on historical cost as a measure of fair value.[23] A survey of current practices in other jurisdictions, summarized in Table 2, also shows that the historical cost approach is in use in some other countries, but to a lesser extent than in the US. **Appendix A** summarizes the regulatory asset base methodologies used by European regulators in electricity, gas, water and telecommunication sectors in Belgium, France, Germany, Italy, Netherlands, Spain and United Kingdom.

**Table 1 – All Fair Value States in the US Incorporate Original Cost Information**

| State | 1992-93[1] | Current[2] |
|---|---|---|
| Arizona | The Commission may weight original and reproduction cost components of the rate base. However, three of the eight recent electric rate cases were decided on the basis of original cost. | The ACC uses an end-of-test-year fair-value rate base, which is generally determined by an equal weighting of net original cost and "reconstruction cost new." The authorized fair-value return is based upon the return needed to recover the overall cost of capital as approved by the Commission. |
| Indiana | Fair value is employed with "tandem consideration of historical cost rate base." | Although Indiana is statutorily a fair value state, the URC has, in most instances, calculated its fair value rate base and return findings after having determined a return on original-cost rate base. |
| Maryland | "Fair value" is usually equated to net original cost. | The PSC relies on average original-cost rate bases for test periods that are fully historical at the time rate decisions are issued. |
| Missouri | Fair value is required by statute to be considered at least as one factor among others for water companies, and where original cost applies to other utilities. | The PSC generally relies on a year-end original-cost rate base, but, by law, must consider fair value for utilities other than telecommunications companies. |
| New Mexico | The commission gives 50 percent weight to original cost and 50 percent to depreciated reproduction cost. | For energy utilities, the PRC relies upon a year-end original-cost rate base for a historical test period, adjusted for known and measurable changes. |

Sources:
[1] NARUC
[2] Regulatory Research Associates

[22] NARUC "Annual Report," 1976 as cited in Goodman, Leonard S. The Process of Rate Making. Public Utility Reports, Inc. (Vienna, Virginia, 1998), p. 762.

[23] The source of this information is the Regulatory Research Associates' publication, Regulatory Focus.

**Table 2 – Modeled and Historic Cost Rate Base in Other Jurisdictions**

| | Model Rate Base | Historic Cost Rate Base | Mixed |
|---|---|---|---|
| **Belgium** | √ | | |
| **France** | | | √ |
| **Germany** | | √ | |
| **Italy** | √ | | |
| **Netherlands** | √ | | |
| **United Kingdom** | | √ | |
| **Australia** | | | |
| **New South Wales** | | | √ |
| **South Australia** | | √ | |
| **Queensland** | √ | | |
| **Grenada** | | √ | |
| **New Zeland** | √ | | |
| **Colombia** | √ | | |
| **Chile** | √ | | |
| **Jamaica** | √ | | |
| **St. Lucia** | √ | | |

**Sources:**

Kenessjay Systems Limited. *Regulated Industries Commission. Analysis of Investment Plans and Advisory on Asset Valuation Methodology in Respect of the Trinidad and Tobago Electricity Commission.* (March 2006), pages 69 - 70.
NARUC, Utility Regulatory Policy pp. 66-67, 71-72, 510-37, cited in: Goodman, Leonard S. The Process of Rate Making. Public Utility Reports, Inc. (Vienna, Virginia, 1998), pp. 770-71.
Commission de Regulation de L'Energie. URL: http://www.cre.fr
Association of German Network Operators URL: http://www.vdn-berlin.de/
l'Autorità per L'Energia Elettrica e il Gas. URL: www.autorita.energia.it
DTE. URL: http://www.dte.nl/;
Ofgem. URL: www.ofgem.gov.uk

## D. Pros and Cons of Modeled Rate Base and Historic Cost Rate Base

### 1. Historic Cost Rate Base

The historic/original cost approach to valuing rate base has a number of advantages, including:

- The determination of original cost is a fairly simple and objective process, while the determination of the fair value can be more subjective.
- With original cost data, investors can readily assess the relationship between actual outlays and future income.
- All financial information presented on an original cost basis is uniform, hence comparable, contributing to the clarity of the information available to the investors and the public.

- The utility is treated fairly. The utility is allowed to recover a return on and of its actual investment in utility plant. Treatment is also symmetrical, as both the return on and of are based on the same metric, actual historic cost.
- Actual costs are verifiable, increasing the transparency and credibility of the regulatory framework.
- The approach simplifies regulatory accounting—there is no need to keep two sets of books, one using historical cost and one using replacement cost.
- The approach avoids the need for a fair value study every few years as well as the annual study to update the indices used to update fair value each year.

Some disadvantages of Barbados switching to original costs might be:

- Changing policies might reduce the credibility of the regulator with investors.
- There might be adverse effects on the utility's finances. If the regulator were to discontinue the use of RCN for ratemaking purposes, the Company's management and/or its auditor might decide that there is not a sufficient foundation for using reproduction cost new for financial reporting purposes.[24]

### 2. Reproduction Cost New Rate Base

Some frequently cited advantages of the RCN approach (and other modeled rate base approaches) are:

- RCN may provide a better signal for market entry decisions because the utility's prices are based on costs that are comparable to the costs that a competitor would have to bear to enter the market. However, market entry does not appear to be a relevant issue in Barbados.
- Fair value protects investors from inflation. However, use of historic cost does so as well, because the utility would have an opportunity to file a rate case if its costs were affected by inflation.
- RCN is a better method if accounting records are poor. However, this does not appear to be the case in Barbados.

Some disadvantages of the RCN approach are:

- RCN involves more subjectivity than the original cost methodology.

[24] While NERA does not, and can not, have an opinion on these accounting and financial reporting issues, the regulator should consider the effect of a possible switch to historic cost on the utility's financial integrity.

- The use of RCN in a rate case requires more preparation by the utility staff and the regulator's staff, and this cost is ultimately borne by ratepayers.
- RCN lacks predictability.
- RCN may misestimate the actual economic value of the assets.
- The approach requires costly rate base studies.
- The method for determining depreciation reserves under RCN is often controversial.

### 3. Analysis

Moving to historic cost to value BL&P's rate base would provide a number of benefits that outweigh any costs of moving away from the reproduction cost new method. A primary benefit is that historic cost rate base is based on actual and verifiable costs. RCN, in contrast, is inherently subjective in nature. While we have not examined all of the many details of the methodology used to calculate BL&P's RCN in the KEMA report,[25] for example, it is clear that the analysis is based on a myriad of assumptions, which only very detailed analysis could validate.

Regulators, including the FTC, typically have considerable discretion in implementing regulatory policy. *Furthermore, historic cost has been used in the past in Barbados as a measure of fair* value.[26] Thus, from a public policy perspective, we see little obstacle to moving to historical cost as the measure of rate base.

We are sensitive to the question of whether moving to historic cost rate base might have adverse effects on the Company's financial integrity (and cost of capital), recognizing that utility customers benefit from a utility's ability to raise the capital needed to provide safe, adequate, and reasonable services at a reasonable cost in good markets and bad. We have investigated this question and conclude that the change from reproduction cost new to historic cost rate base should not have a markedly adverse effect on the utility's financial integrity.

**Recommendation:**

We recommend that BL&P's rate base be defined in terms of historic cost.

[25] KEMA, "Utility Fixed Assets Valuation Study: The Barbados Light & Power Company Limited," January 15, 2006.

[26] Barbados used both historic costs and reproduction cost new (RCN) in an electric rate case decision in 1979. In this rate case decision, the fair value of fixed assets portion of rate base was determined to be the sum of production plant (55% historic costs and 45% RCN), distribution plant (45% historic costs and 55% RCN), general property (60% historic costs and 40% RCN), and lands and rights-of-way (50% historic costs and 50% RCN). *See*: Price Waterhouse Barbados, "Report on Barbados Light and Power Company Limited: 1982 Rate Application," May 11, 1982. Historic cost rate base is also used in valuing the rate base of Cable and Wireless.

## E. Other Accounting Issues

Effective regulation requires that regulators define the consistent and sustainable accounting procedures to be used by regulated companies. The early history of utility regulation in the US was characterized by notorious accounting abuses, including overstated expenses, unverifiable investments in plant and equipment, a lack of separation between utility and non-utility businesses and overcapitalization. In the US, such abuses were effectively ended in 1938 with the adoption by the Federal government of the Uniform System of Accounts. The goals of good regulation are frustrated without the regulator's ability to periodically assess costs because of the lack of detailed and reliable figures from agreed accounting sources.

Regulatory accounts exist separately from statutory (*i.e.*, accounts for investors) or tax accounts, primarily because regulators require much more detailed cost information to oversee the efficacy and fairness of rate calculations (among other reasons). Taxing authorities, in contrast, need only more aggregated accounting information. Without a detailed set of accounts, regulators are unable to ensure consistent reporting among regulated companies, are incapable of preventing pricing mistakes or abuses by the company (such as undue cross subsidies between customers), and cannot uncover illicit affiliate transactions or the subsidization of unregulated subsidiaries.

There is a marked difference between the character of price regulation in the presence and in the absence of clear accounting rules. For example, the Uniform System of Accounts rarely leave US energy utilities and their regulators in major dispute over basic financial issues (such profitability, depreciation expenses, customer contribution, the admissibility of particular costs or the treatment of unregulated affiliates). In the UK, however, without a regulatory-mandated accounting system for regulating prices, major components of every rate review involve costly and time-consuming fights over basic accounting and financial items.

The following points discuss certain accounting policies of BL&P.

### 1. Treatment of Major New Capital Investments

BL&P bases its accounts on FERC's Uniform System of Accounts, although the Company deviates from or modifies these standards in some respects. New capital investments are assigned a project number and recorded as work in progress until put in service. In a data request response, BL&P explained that as individual sections of the project become operational, these can be capitalized while unfinished sections of the same project remain recorded as work in progress until finished.[27]

[27] Response to Data Request. BLPC Policy on Capital Assets – Item 2. [Hereinafter, Item 2]

Major assets are categorized as:

- Generation;
- Transmission and distribution, and
- General property.

In many jurisdictions, construction-work-in-progress (CWIP) is excluded from the rate base because it does not pass the "used and useful" test; *i.e.*, only plants currently providing or capable of providing utility services to the consuming public are allowed in the rate base. Only property that is used and useful should earn a rate of return.[28]

While it is appropriate to remove some types of assets from construction work in progress once individual sections become operational, that would not be the case for generation, which should not be removed from construction work in progress unless it has met specific tests that verify that the equipment is operating as designed. BL&P notes that if generation plant is commissioned during the year, then that plant is removed from construction work in progress at the end of the month in which it was commissioned.[29]

Based on our limited financial review, we believe that BL&P's treatment of major new capital investments is reasonable, and consistent with standard accounting rules and international best practice for electric utilities.

### 2. Rules on Capitalization of Expenditures

BL&P capitalizes investment annually, at the end of the financial year; however, if a major generation plant is commissioned during the year, the plant is capitalized at the end of the month in which it was commissioned.[30] Contributions received towards construction of electric plant are credited to the cost of construction or are shown as deferred credits in the case where construction has not yet started. Interest charges are accrued during the period of construction of property, plant and equipment and are capitalized.[31]

[28] Hahne, Robert and Aliff Gregory. *Accounting for Public Utilities.* Lexis Nexus, 1983. p. 4.03.

[29] Item 2, *supra* Note 27.

[30] Response to Data Request. BLPC Policy on Capital Assets – Item 2.

[31] Barbados Light and Power Annual Report 2004, p. 20.

Normal practice in the US is to capitalize an allowance for funds used during construction (AFUDC) as part of CWIP.[32] AFUDC includes capitalization of carrying charges on the equity segment of AFUDC as well as the debt segment.[33] This accounting treatment allows a utility to earn a return on capital costs incurred while a facility is under construction. When construction of the plant is completed, the rate base will include the actual costs of building the facility and the capitalized AFUDC charges. During the life of the plant, the utility earns a return on and depreciates the cost of constructing the plant, including the AFUDC.[34]

BL&P capitalizes interest during construction, but does not include an equity return. In the US, carrying charges for construction of utility plant is based on the utility's weighted average cost of capital (WACC).

**Recommendation:**

We suggest that the Company and the Commission consider including an equity return on plant under construction (*i.e.*, use the WACC for this purpose).

### 3. Depreciation Policies

BL&P depreciates its assets using the straight line method, using rates required to amortize the carrying value over the estimated years of service life of the asset. The rates are as follows:

- Generation: 2 to 7 percent;
- Transmission and Distribution: 2 to 14 percent, and
- Other: 2 to 37 percent.

It is our understanding that the Company records depreciation expense on its income statement based on what it believes to be "the economic useful lives of the assets for financial reporting purposes."[35] Recovery of the dollars invested in a plant in service is permitted over the plant's estimated useful life by a systematic depreciation charge to cost of service, normally on a straight-line basis with the reproduction cost new plant valuation (net of estimated salvage less

[32] Leonard Hyman explains that "AFUDC is a mechanism whereby the cost of money is added to the plant account on the balance sheet." *See*: Leonard Hyman *America's Electric Utilities: Past, Present and Future*. (Arlington, VA: Public Utilities Reports, Inc., 1985), p. 207.

[33] See: Hahne, Robert and Aliff Gregory. *Accounting for Public Utilities*. LexisNexis, 1983, p. 12.02; FASB Statement No. 71.

[34] Leonard Hyman, America's Electric Utilities: Past Present and Future, Arlington, VA, Public Utilities Reports, Inc., 1985, pp. 141-42.

[35] BL&P *Annual Report* with audited results, p. 16.

removal cost) recovered in each period over the estimated economic service life of the fixed assets.

Analysis of BL&P's depreciation charges is complicated by the fact that the Company values its assets based on reproduction cost new rather than historic costs. Thus, BL&P records depreciation expense based on the reproduction cost new asset valuation for financial reporting purposes. For example, the Company recorded $53.526 million of depreciation expense on its income statement in 2005.[36] Of this $53.526 million, about $13.956 million is depreciation expense on the "revaluation element" of the Company's asset valuation and about $39.580 million is the depreciation expense on the original cost asset valuation.[37]

As outlined above, we recommend that the Commission move to use of historic cost rate base as the measure of fair value, which would mean that the Company's depreciation charges would also reflect historic costs. This would increase the transparency and understandability of the Company's regulatory accounting.

As a result of transfers from the special reserve, it is our understanding that retained earnings were increased by $7.369 million and $51.346 million in 2004 and 2003, respectively.[38] We have been informed that the Company does this because "[t]he Directors consider it prudent to set aside in a special reserve the difference in the depreciation amounts arising therefrom."[39]

We understand that the Company calculates the difference between the depreciation expense it believes appropriate and the depreciation expense that results from using the asset lives specified by the Commission in its 1983 order. Then, the Company records this difference in a "special reserve" account." Next, the balance in the special reserve is transferred directly to retained earnings. The effect is to increase retained earnings by the difference between the depreciation expense that the Company believes correct and the depreciation expense resulting from the asset lives approved by the Commission.

We are puzzled by this accounting treatment. It appears that the Company reports lower earnings for financial reporting purposes by using shorter asset lives than those approved by the Commission. The Company then "reverses out" the effect of these shorter asset lives by increasing its retained earnings directly. We note that it is unusual for direct adjustments to be made to retained earnings. Davidson, Stickney, and Weil note, for example, that "[n]early all items that cause the total of retained earnings to change during a period result from transactions

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[36] *Id.*, p. 4.

[37] *Id.*, p. 5.

[38] *Id.*, pp. 4-5.

[39] *Id.*, p. 16.

reported in the income statement during that period."[40] The only exceptions that they note are the corrections of errors and prior period adjustments.

**Recommendation:**

We suggest that it is time to reevaluate the Company's depreciation rates to determine whether the useful lives of utility plant in Barbados are shorter than those set by the Commission in 1983.[41] This review could be done without a rate case.

### 4. Retirement of Assets

According to BL&P's practice, when depreciable plant and equipment other than motor vehicles and property are retired, the gross book value, less proceeds net of retiral expense, is charged to accumulated depreciation. For disposals of motor vehicles and property, the asset cost and accumulated depreciation are removed with any gain or loss credited or charged to current operations.[42] The Company's approaches appear to be reasonable and consistent with standard utility practice.

## F. Fair Rate of Return

Utility rates are set based on a test year, so in any particular year the utility may in fact earn more or less than the rate of return authorized in the rate case. Nevertheless, the FTC requested that we calculate the rates of return earned in 2002-2005 and compare those to the rate of return authorized in the 1983 rate case. We also developed an estimate of BL&P's current cost of capital, based on market rates of returns on similar investments, for comparison to the Company's rate of return in 2005.

### 1. Analysis of BL&P's earnings/rate base (2002-2005)

The first task was to determine what overall rate of return and return on equity was granted in the 1983 rate case. The PUB did not explicitly state an overall rate of return or return on equity in its rate Order. However, given the dollar amounts for rate base, total return, and equity return in the Order and a forecast of BL&P's long-term debt, the PUB implied an overall rate of return of 7.72 percent, a return on equity of 9.35 percent, and a cost of debt of 6.72 percent, as shown in **Table 3**.

[40] Davidson, Stickney, and Weil, *Financial Accounting*, 4th ed. (Chicago: Dryden, 1985), p. 550.

[41] We are aware that BL&P commissioned a depreciation study for electric services property. *See*: E. Wotring Associates, Inc., "Depreciation Study for Electric Services Property as of January 1, 2002," December 2002.

[42] Barbados Light and Power Annual Report 2004, p. 21.

**Table 3 – Derivation of Rates of Return Implied in 1983 Rate Case**

| | BP&L Capital Structure (Percent) (1) | BP&L Capital Structure (Amount) (2) | Allowed Return (Amount) (3) | Implicit Allowed Rate of Return (Percent) (4) (3)/(2) | Weighted Average Cost of Capital (Percent) (5) |
|---|---|---|---|---|---|
| Debt | 61.8% [1] | 163,066 | 10,959 | 6.72% | 4.15% |
| Equity | 38.2% | 100,802 | 9,421 | 9.35% | 3.57% |
| Total | | 263,868 | $ 20,380 | | **7.72%** |

[1] Based on 1983 Audited Long Term Debt and Equity Net of Revaluation Surplus.

The next task was to analyze the company's earnings and RCN rate base for 2002-2005. The rate of return on equity for 2002-2005 was calculated in three steps. First, BL&P's annual reports were used to derive the equity-to-total-capitalization ratio (excluding revaluation surplus). Second, the annual average rate base was calculated by taking the arithmetic mean of the RCN rate base for the current year and the previous year. The average annual equity share of rate base was then calculated by multiplying the percent equity over total capitalization by the average annual rate base. Third, the return on equity was derived by dividing the net income by the average annual equity share of rate base.

The 1983 Order authorized a return that covered BL&P's interest expense, plus a return on the equity share of RCN rate base equal to 9.35 percent. Compliance with this Order would imply that BL&P cover its actual interest expense in a subsequent year plus that same percentage return on the equity portion of RCN rate base. **Table 4** shows that BL&P earned more than the 9.35-percent rate of return authorized in 1983 in 2003 and 2004, but less in 2002 and 2005.

**Table 4 – Comparison of Earned and Allowed Rates of Return, 2002-2005 using PUB-Authorized Depreciation Rates and RCN Rate Base**

| | Allowed ROE from PUB Order | Earned ROE | | | |
|---|---|---|---|---|---|
| | 1983 | 2002 | 2003 | 2004 | 2005 |
| **RCN Rate Base ($000)** | | | | | |
| (1) *Rate Base ($ Thousands)* | $ 263,868 | $ 465,926 | $ 489,520 | $ 673,559 | $ 669,320 |
| (2) Average RCN Rate Base | $ 263,868 | $ 465,926 | $ 489,520 | $ 581,540 | $ 671,440 |
| (3) Equity Contribution of Rate Base (2)x(12) | $ 100,802 | $ 394,081 | $ 386,650 | $ 435,290 | $ 523,553 |
| (4) Operating Income | $ 20,380 | $ 37,114 | $ 44,160 | $ 55,293 | $ 47,836 |
| (5) Net Income | $ 9,421 | $ 33,782 | $ 40,268 | $ 51,537 | $ 40,769 |
| (6) ***Rate of Return on Rate Base (4)/(2)*** | *7.72%* | *7.97%* | *9.02%* | *9.51%* | *7.12%* |
| (7) **Rate of Return on Common Equity Portion of Rate Base (5)/(3)** | **9.35%** | **8.57%** | **10.41%** | **11.84%** | **7.79%** |
| **Capital Structure Used in Analysis** | | | | | |
| (8) *Total Shareholder's Equity, including RCN Reval.* | $ 97,207 | $ 438,161 | $ 491,717 | $ 528,543 | $ 540,919 |
| (9) RCN Revaluation Surplus | $ 49,049 | $ 133,795 | $ 162,151 | $ 165,622 | $ 154,635 |
| (10) Actual Equity Amount (8)-(9) | $ 48,158 | $ 304,366 | $ 329,565 | $ 362,921 | $ 386,284 |
| (11) Long-Term Debt | $ 77,904 | 55,489 | 87,682 | 121,935 | $ 109,113 |
| (12) Total Capital (10)+(11) | $ 126,062 | $ 359,855 | $ 417,248 | $ 484,856 | $ 495,397 |
| (13) % Equity/ Total Capital (10)/(12) | 38.2% | 84.6% | 79.0% | 74.9% | 77.97% |

**Notes:**
Row [2] Average rate base is not used for 2002 due to lack of rate base data.

Source: Barbados Light and Power documents and annual reports.

We believe that the analysis summarized in **Table 4** provides the best benchmark of the earned return of BL&P, for the 2002-2005 period, compared to the return authorized in 1983. This analysis uses the depreciation lives approved by the regulator at that time and uses RCN rate base.

**Table 5** shows the results for 2002-2005 using rate base valued at Historic Cost, BL&P's preferred depreciation rates, and the same capital structure derived in the lower portion of Table 4. The earned rates of return on equity are somewhat higher in Table 5 than in Table 4. The higher depreciation expenses in Table 5 mean lower net income in the numerator, but the lower amounts of equity reduce the denominator. Thus, the two changes move the earned rate of return in opposite directions.

**Table 5 – Earned Rates of Return, 2002-2005 using BL&P Depreciation Rates and Historic Cost Rate Base**

| | | Earned ROE | | | |
|---|---|---|---|---|---|
| | | 2002 | 2003 | 2004 | 2005 |
| **HC Rate Base ($000)** | | | | | |
| (1) | End-of year Rate Base ($ Thousands) | $ 410,353 | $ 407,254 | $ 444,728 | $ 590,859 |
| (2) | Average HC Rate Base | $ 410,353 | $ 408,803 | $ 425,991 | $ 517,794 |
| (3) | *Equity Contribution of Rate Base* | $ 347,077 | $ 322,896 | $ 318,860 | $ 403,748 |
| (4) | Operating Income | $ 33,692 | $ 37,759 | $ 51,138 | $ 38,663 |
| (5) | Net Income | $ 30,360 | $ 33,867 | $ 47,382 | $ 31,596 |
| (6) | **Rate of Return on Rate Base (4)/(2)** | **8.21%** | **9.24%** | **12.00%** | **7.47%** |
| (7) | **Rate of Return on Common Equity Portion of Rate Base (5)/(3)** | **8.75%** | **10.49%** | **14.86%** | **7.83%** |

## G. BL&P's Nominal and Real Cost of Equity Today

We also estimated, using available information, the return on equity required to compensate BL&P's equity investors today at market rates, based on the average of a discounted cash flow (DCF) and capital asset pricing method (CAPM) analysis of a comparable group of electric utilities and adjusted for the business risks faced in Barbados. The required return must be stated in real terms if it is applied to a rate base stated in reproduction cost new rate base terms, because the RCN rate base includes the effects of inflation. If the rate base is stated based on historic costs, a nominal rate of return is appropriate.

The first step in this analysis is to define a group of 16 US electric utilities comparable to BL&P in key respects. We used four criteria to select these utilities. Each firm: (1) derives at least 80 percent of its operating earnings from regulated operations; (2) has capitalization of no more than $10 billion; (3) is not involved in a take-over or merger; and (4) has paid stable or increasing dividends over a recent period. Because these companies are US-based firms, we made an adjustment for the additional business risks faced by investors in Barbados. The selected utilities are shown in **Table 6**.

**Table 6 – Comparable US Electric Utilities**

| | |
|---|---|
| 1 | Alliant |
| 2 | Avista Corp. |
| 3 | Central Vermont Public Service |
| 4 | Cleco |
| 5 | DQE |
| 6 | Empire District Electric |
| 7 | Energy East Corp. |
| 8 | Green Mountain Power |
| 9 | Hawaiian Electric |
| 10 | MGE Energy |
| 11 | NSTAR |
| 12 | Puget Energy, Inc. |
| 13 | UniSource Energy |
| 14 | Vectren Corp. |
| 15 | Westar |
| 16 | Wisconsin Energy |

Note that if the result of the fuel adjustment project commissioned by the FTC is to change the mechanism and increase risk of BL&P's fuel cost under-recovery, the group of 16 US electric utility companies may no longer be comparable to BL&P. Most US electric utilities have fuel adjustment mechanisms (or the equivalent) that allow these companies to recover fuel and purchased power costs and directly pass them to customers in rates. The elimination of (or major change in) the fuel adjustment mechanism in Barbados would increase uncertainty in earnings and increase investor risk, thereby increasing BL&P's cost of equity.

The DCF method makes use of the relationship between the current stock price and the expected future stream of dividends in order to calculate investors' estimated discount rate, or cost of equity. The DCF method has a long history of being used to derive the cost of equity for both regulatory and market investment purposes and is the preferred method of rate regulators in the US.

The DCF method is used to estimate the cost of common stock equity by determining the present value of all future income expected to be received from a share of common stock. With the DCF method, the cost of common stock equity is computed as the discount rate that equates a stock's current observed market value with the present value of all future expected returns from holding the common stock (*i.e.*, dividends and capital gains). The prevailing common stock price is assumed to reflect investors' expectations of the value of common stock, including future dividends and price appreciation.

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[43] The research performed by subsequent writers (including Gordon himself) resulted in the equation known as the "Periodic" DCF model. The "Periodic" DCF model generally expresses k, the cost of the common stock equity portion of total capital, as a relationship between the prevailing price of common stock equity, $P_0$, current dividends, $D_0$, and the earnings growth rate, $g$. The "Gordon model" expressed the price of common stock equity, $P_0$, as a function of current dividends, $D_0$, the dividend growth rate, $g$ and the cost of equity capital, $k_e$.

$$P_0 = \frac{D_0}{k_e - g}$$

or, in its popular DCF reformation for utility rate cases:

$$k_e = \frac{D_0(1+g)}{P_e} + g$$

**Table 7** shows the results of the DCF analysis.

[43] See: Myron J. Gordon, *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

## Table 7 – Return on Equity for Comparable Utilities, Using DCF

| Company | Dividend[1] Yield (Percent) | Growth[2] Rate, g (Percent) | Adjusted[3] Stock Price, $P_0$ ($) | Stock Price[4] S&I Adjusted ($) | Unadjusted[5,6] ROE, $k_e$ Before S&I (Percent) | Change (Percent) | S&I[7] Adjusted ROE (Percent) |
|---|---|---|---|---|---|---|---|
| 1 Alliant | 3.39 | 4.00 | 32.32 | 30.54 | 7.38 | 0.20 | 7.58 |
| 2 Avista Corp. | 3.01 | 5.00 | 19.00 | 17.95 | 8.01 | 0.18 | 8.19 |
| 3 Central Vermont Public Service | 4.70 | 7.69 | 21.06 | 19.90 | 12.40 | 0.27 | 12.67 |
| 4 Cleco | 4.35 | 3.29 | 21.37 | 20.19 | 7.65 | 0.25 | 7.90 |
| 5 DQE | 6.34 | 4.32 | 16.45 | 15.55 | 10.66 | 0.37 | 11.03 |
| 6 Empire District Electric | 6.59 | 11.77 | 21.72 | 20.53 | 18.35 | 0.38 | 18.74 |
| 7 Energy East Corp. | 4.78 | 4.04 | 24.25 | 22.91 | 8.82 | 0.28 | 9.10 |
| 8 Green Mountain Power | 3.88 | 3.29 | 27.43 | 25.92 | 7.17 | 0.23 | 7.39 |
| 9 Hawaiian Electric | 4.87 | 4.49 | 26.60 | 25.14 | 9.36 | 0.28 | 9.64 |
| 10 MGE Energy | 4.79 | 6.72 | 30.64 | 28.95 | 11.50 | 0.28 | 11.78 |
| 11 NSTAR | 4.35 | 4.59 | 28.20 | 26.64 | 8.94 | 0.25 | 9.19 |
| 12 Puget Energy, Inc. | 5.11 | 6.40 | 20.81 | 19.66 | 11.51 | 0.30 | 11.81 |
| 13 UniSource Energy | 2.57 | 3.42 | 30.56 | 28.88 | 5.99 | 0.15 | 6.14 |
| 14 Vectren Corp. | 4.89 | 5.67 | 25.73 | 24.31 | 10.56 | 0.28 | 10.85 |
| 15 Westar | 4.66 | 5.38 | 20.79 | 19.65 | 10.04 | 0.27 | 10.31 |
| 16 Wisconsin Energy | 2.40 | 7.73 | 39.50 | 37.33 | 10.13 | 0.14 | 10.27 |
| **Average** | | | | | **9.91%** | **0.26%** | **10.16%** |

Notes:
[1] Forward Annual Dividend per Share (Df) = {[$D_0$*(1+g)]/$P_0$}.
[2] Simple average of Analysts' Estimated Value Line growth and Zacks growth.
[3] Spot-Date Adjusted Stock Price.
[4] Adjusted Price=0.945*Ex-Div Price. Adjustment based on flotation cost of 5.50 percent, from Victor M. Borun and Susan L. Malley, "Total Flotation Costs for Electric Company Equity Issues."
[5] Calculated using Quarterly DCF Formula: Cost of Equity (ke) = {[$D_0$*(1+g)]/$P_0$} + g
[6] Not adjusted for selling and issuance expenses.
[7] ROE adjusted by selling and issuance expenses.

The CAPM approach estimates the cost of equity as the sum of the risk-free return, a company-specific return, and a country risk premium. On **Table 8** we calculated and averaged the CAPM results for the 16 comparable US utilities. The company-specific risk premium is composed of the product of a company-specific beta and a market risk premium.

**Table 8 – Return on Equity for Comparable Utilities, Using CAPM**

| No. | Company | 10-Year T-Note Return (Rf)[1] | Beta Value Line[2] | Market Risk Premium Top-Down DCF - 10 Yr T-Bond Return[3, 4] | CAPM Cost of Equity[5] Top-Down DCF - 10 Yr T-Bond Return |
|---|---|---|---|---|---|
| | | % | | | % |
| 1 | Alliant | 4.56 | 0.85 | 8.17 | 11.50 |
| 2 | Avista Corp. | 4.56 | 0.90 | 8.17 | 11.91 |
| 3 | Central Vermony Public Service | 4.56 | 0.60 | 8.17 | 9.46 |
| 4 | Cleco | 4.56 | 1.15 | 8.17 | 13.95 |
| 5 | DQE | 4.56 | 0.85 | 8.17 | 11.50 |
| 6 | Empire District Electric | 4.56 | 0.70 | 8.17 | 10.28 |
| 7 | Energy East Corp. | 4.56 | 0.85 | 8.17 | 11.50 |
| 8 | Green Mountain Power | 4.56 | 0.60 | 8.17 | 9.46 |
| 9 | Hawaiian Electric | 4.56 | 0.70 | 8.17 | 10.28 |
| 10 | MGE Energy | 4.56 | 0.70 | 8.17 | 10.28 |
| 11 | NSTAR | 4.56 | 0.75 | 8.17 | 10.68 |
| 12 | Puget Energy, Inc. | 4.56 | 0.80 | 8.17 | 11.09 |
| 13 | UniSource Energy | 4.56 | 0.70 | 8.17 | 10.28 |
| 14 | Vectren Corp. | 4.56 | 0.80 | 8.17 | 11.09 |
| 15 | Westar | 4.56 | 0.85 | 8.17 | 11.50 |
| 16 | Wisconsin Energy | 4.56 | 0.70 | 8.17 | 10.28 |
| | **Average** | | **0.78** | | **10.94%** |

Notes:

[1] From *The Value Line Selection and Opinion*, March 3, 2006.

[2] *The Value Line Investment Survey:* 30 December 2005 (Edition 5), 10 February 2006 (Edition 11), 3 March 2006 (Edition 1).

[3] The formula used is Risk Premium = [[Do*(1+g)]+g] - Rf

[4] Dividend yield for S&P 500 is from Standard & Poors Online, Indices, S&P 500, Month End Data. Five-year earnings growth rate is from Yahoo! Finance (First Call). Resulting DCF for S&P 500 is 12.83%.

[5] Cost of Equity = Rf + Beta (RM - Rf), where Rf is the return on the 10-year Treasury Bond, and (RM - Rf) is the market premium computed as described in footnote [3] and [4].

The DCF analysis of 16 comparable US utilities derives a nominal cost of equity of 10.16 percent while the CAPM analysis results in a nominal cost of equity of 10.94 percent. Averaging the results from the two approaches yields a nominal return on equity of 10.55 percent.

Next, we made an adjustment for the additional business risks faced by investors in Barbados compared to the US. The average return on equity of 10.55 percent was increased by a country risk premium for Barbados of 1.35 percent. Country risks premiums reflect the additional risk that investors assume when investing in a particular country due to economic and/or political uncertainties.[44] The estimated nominal cost of equity for Barbados, based on available information, is therefore 11.90 percent.

[44] Aswath Damodaran, "Estimating Equity Risk Premiums," New York University Stern School of Business. Professor Damodaran published country risk premiums as of January 2006.

**Table 9** shows the calculation of BL&P's estimated current WACC, using the Company's 2005 end-of-year capital structure to reflect the most up-to-date information. The resulting nominal WACC, 10.40 percent, was used as the target return in the embedded cost analysis, which in turn was based on historic rate base valuation.

For use with a rate base valued at RCN, the nominal rate of return must be adjusted to avoid double-counting inflation.[45] The inflation factor used in this conversion was 2.7 percent.[46] This yielded a real WACC of 7.49 percent. The corresponding real cost of equity is 8.96 percent. This conversion from nominal to real rates of return is very sensitive to the inflation rate assumed, and is another illustration of why historic cost valuation of rate base is more objective than RCN.

**Table 9 – Current Weighted Average Cost of Capital for BL&P (Nominal and Real)**

| | 2005 BL&P Capital Structure (Amount) | 2005 BL&P Capital Structure (Percent) | Nominal Average Cost (Percent) | WACC (Percent) | |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | |
| Debt | $ 109,112,786 | 22.03% | 5.07% | 1.12% | |
| Equity | $ 386,284,245 | 77.97% | 11.90% | 9.28% | |
| Total | $ 495,397,031 | 100.00% | **WACC:** | **10.40%** | *nominal* |
| | | | **WACC:** | **7.49%** | *real* |

The estimated current real WACC and return on equity are above BL&P's earned rates of return on RCN in 2005. The estimated current nominal WACC and return on equity are also above the earned rates of return in 2005, if computed using historic cost rate base and BL&P's preferred depreciation rates, as shown in **Table 10.**

[45] To find the real return on equity ($k_r$) using the nominal return on equity ($k_n$), the following equation is used:

$$k_r = [\,(1+k_n)\,/\,(1+i)] - 1$$

[46] For consistency with the US-based nominal rates of return, we used the average of the US inflation rate (Production Price Index) forecast in 2006 and 2007 as the expected rate of inflation. Source: "Blue Chip Econometric Detail. Supplement to Blue Chip Economic Indicators. Vol. 22. March 10, 2006.

**Table 10 – Comparison of Estimated BL&P Current Cost of Capital and Year 2005 Rates of Return**

| | | Return on Equity | Return on Rate Base |
|---|---|---|---|
| | RCN Rate Base | | |
| (1) | Estimated Market Return for BL&P | 8.96% | 7.49% |
| (2) | Rates of Return Earned in 2005 (assuming PUB Depreciation) | 7.79% | 7.12% |
| | HC Rate Base | | |
| (3) | Estimated Market Return for BL&P | 11.90% | 10.40% |
| (4) | Rates of Return Earned in 2005 (assuming BL&P Depreciation) | 7.83% | 7.47% |

**Recommendation:**

We recommend that in BL&P's next rate case, a market-based return on equity be estimated, using an approach such as the one illustrated above, which averages the calculated cost of equity capital for a sample of comparable US utilities computed using both the CAPM and DCF methods, and adjusts for the country risk premium for Barbados.

## H. Capital Structure Analysis

BL&P has a relatively high equity share (nearly 78 percent) in its capital structure. It is appropriate for a regulator to question the reasonableness of a utility's capital structure for ratemaking purposes. There are three considerations that are noteworthy in determining the appropriate capital structure. First, since this rate proceeding will set rates to be charged for service in future periods, it is appropriate to base the capital structure components upon the best available estimates for the period of time in which the rates will be in effect. The appropriate capital structure should reflect all known changes, including new security issuances and retirements.

Second, modern financial theory suggests that there is a relatively wide zone of reasonableness for capital structures, with capital structures within that zone producing about the same cost of capital.[47]

Third, a utility's management must be granted a measure of discretion as to the type of capital raised. Nevertheless, either too much or too little equity in the capital structure will cause the overall cost of capital to be higher than it otherwise would be. Too little equity in a utility's capital structure will cause the costs of all capital components to be higher, thereby causing the overall cost of capital to be higher. Too much equity in a utility's capital structure will cause the costs of all capital components to be lower, but simultaneously will shift a greater proportion of the capital structure to common equity. Since common equity is the most expensive capital structure component, a high proportion of equity results in a higher overall cost of capital.

One alternative to using the BL&P's current capital structure for purposes of setting an allowed WACC is to use the higher-end of the range of capital structures for Caribbean utilities. The Company should not be held to the mean, but to the higher end of the reasonable range of return on equity for Caribbean electric utilities. Further, a utility's management must be granted a measure of discretion as to the type of capital raised.

The average equity-capital-to-total-capitalization ratio for Caribbean utilities as reported in 2004 was 64.2 percent and the high end of the range was 75-percent equity capital.[48] Using 75-percent equity would result in a lower WACC, as shown in **Table 11.**

**Table 11 – Nominal and Real WACC Assuming 75% Equity / 25% Debt**

| | Assumed Capital Structure (Percent) | Nominal Average Cost (Percent) | | Weighted Cost (Percent) | |
|---|---|---|---|---|---|
| | (1) | (2) | | (3) | |
| Debt | 25.00% | 5.07% | | 1.27% | |
| Equity | 75.00% | 11.90% | | 8.93% | |
| | | | | *nominal* | *real* |
| Total | 100.00% | | **WACC** | **10.19%** | **7.30%** |

[47] See Roger Morin, *Utilities' Cost of Capital* (Arlington, VA: PUR, 1984), p. 268.

[48] This report presents debt-to-total-capital ratios. The equity ratio is equal to 1 minus the debt-to-capital ratio. CARILEC, "Benchmarking of Caribbean Utilities," October 2004, p. 47.

**Recommendation:**

We recommend that, at a minimum, the Commission scrutinize carefully the reasonableness of the Company capital structure in a future rate case. Whether the Commission uses the Company's actual capital structure or imposes a hypothetical one in a future rate case the determination of an appropriate capital structure should reflect the capital structure that would be reasonable for ratemaking purposes.[49]

[49] The Commission should keep in mind that imposing a capital structure that sharply diverges from its actual capital structure would hurt the Company's ability to raise funds from the capital markets. This may result in underinvestment in critical infrastructure required to provide safe, reliable and efficient utility services to its customers.

## V. Class Revenue Allocations

Ideally each customer class should pay its cost of service, so that there are no class cross-subsidies. In fact, in most countries social policies do result in some cross-subsidies, either as a transition mechanism to avoid sudden bill increases, as a permanent policy to protect disadvantaged populations, or both. Even in cases where there is a social policy reason for cross-subsidies, it is important to calculate class cost of service, so that the size of the subsidy can be discussed and the final decision on cross-subsidy is transparent.

There are two notions of "class cost of service" that can be used in this analysis. The first is to define class cost of service as the allocation of embedded costs that results when each class pays an equal rate of return on allocated rate base. A class embedded cost study takes the costs associated with plant in service, including operating costs in the test year, and allocates them to classes based on selected measures of use. Such studies are often considered a fair way to allocate the revenue requirement, although there are numerous ways to do the allocation and the choice of methods is often highly contested. The problem is that there are no theoretical (engineering or economic) bases for choosing one method over another.

The second way to define cost of service is with reference to the marginal cost of serving each class. Marginal costs are the forward-looking costs of supplying an additional kW, kWh or customer in each class. Marginal costs vary by time of use (time-of-day and, sometimes, season) and voltage level of service. When charged as rates, marginal costs signal to consumers the cost implications of their decisions to use more or less electricity, and provide consumers with the information they need to make efficient energy choices. We recommend that class revenue allocations be based, at least in part, on marginal cost revenues because of these efficiency properties of the approach.

For the sake of efficiency, no customer class (or indeed individual customer) should be charged less than marginal cost. Marginal costs therefore set the floor for efficient class revenues. However, the marginal costs of serving each class (marginal cost revenues) rarely sum to the total revenue requirement. The resulting marginal cost revenue "gap" (which can be positive or negative) must be closed by adjusting some elements of electricity rates away from marginal cost. If efficiency is the primary objective, this adjustment should be done in a way that preserves the marginal cost price signals for the most price-sensitive classes, and makes adjustments within a class to the elements of the rate to which customers are least sensitive. For example, adjusting the monthly fixed charge should have little effect on kWh consumption, since customers will have to pay the same fixed charge no matter how many kWh they consume.

In practice, whether class revenue allocation is based on embedded or marginal costs, other rate objectives typically influence class revenue allocations. For example, the cost studies may suggest that Class 1 should receive a 40-percent increase in revenue allocation, while Class 2 should receive a 20 reduction. In most jurisdictions, these cost-justified adjustments would be phased in over several rate cases (or rate adjustments), rather than implemented all at once.

In this project we calculated both class embedded costs (based on a 2005 test year) and 2006 class marginal cost revenues (based on 2005 consumption levels).[50] The embedded study used the historical cost definition of rate base and depreciation. It shows that at current rate levels (which produce an overall rate of return on investment of 6.5 percent), class rates of return vary significantly. An allocation of total revenue requirement based on embedded costs would produce the same rate of return for each class. The current rates of return by class and the rate changes necessary to yield a 6.54-percent rate of return from each class are shown in **Table 12.**

**Table 12 – Current Class Rates of Return and Rate Changes Necessary to Produce Equal 6.54-Percent Rates of Return**

| Rate Class | RORs Currently Earned By Customer Class | Tariff Changes Required to collect same ROR by class |
|---|---|---|
| Domestic | -1.32% | 17.48% |
| Employees | -5.22% | 28.62% |
| General | 8.42% | -3.02% |
| S.V.P. | 11.29% | -7.67% |
| LP | 15.79% | -12.51% |
| Street Lighting | -15.64% | 52.62% |
| Overall | 6.54% | 0.00% |

The embedded study also indicates that, to produce an overall return equal to NERA's estimates of BL&P's current cost of capital of 10.40 percent implies an overall rate increase (including fuel) of about $30 million or 9.0 percent. **Table 13** shows the rate changes necessary for each class to produce this rate of return.

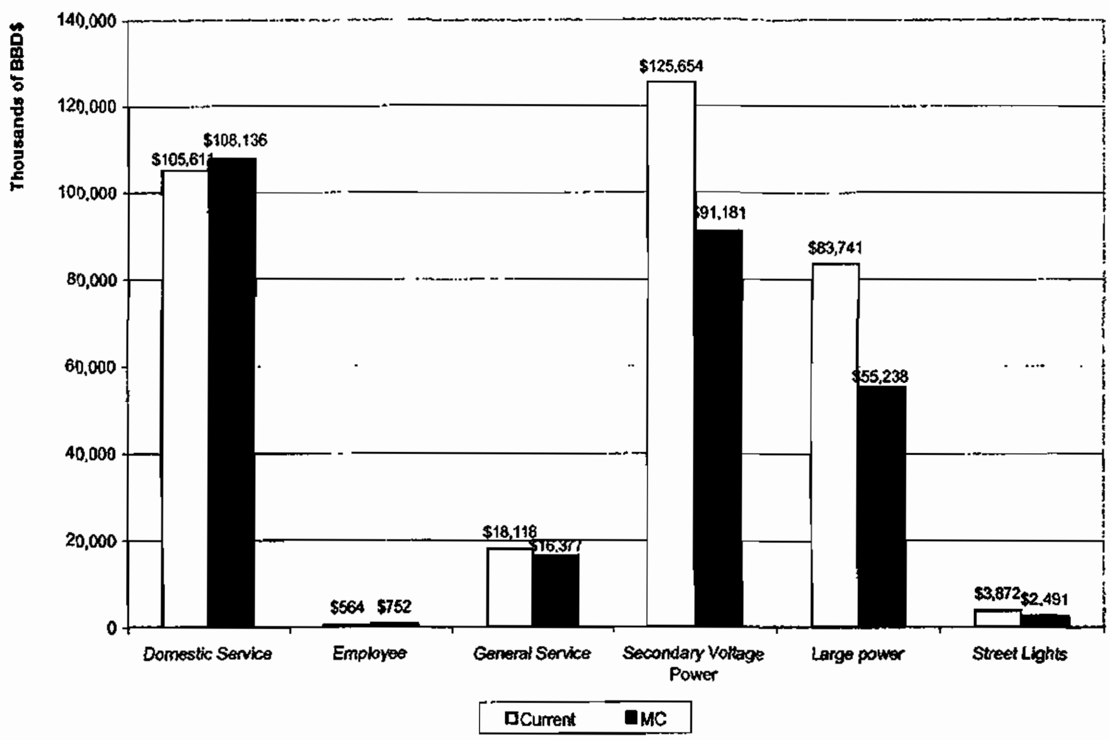
[50] A detailed description of the full embedded cost study is located in Appendix B to this report. The full marginal cost study is located in Appendix C.

**Table 13 – Class Rate Changes Necessary to Produce Equal 10.40-Percent Rates of Return**

| *Rate Class* | Target ROR By *Customer Class* | Tariff Changes Required to Collect the *Target ROR by Class* |
|---|---|---|
| Domestic | 10.40% | 34.74% |
| Employees | 10.40% | 50.67% |
| General | 10.40% | 4.26% |
| S.V.P. | 10.40% | -1.92% |
| LP | 10.40% | -9.72% |
| Street Lighting | 10.40% | 82.36% |
| Overall | **10.40%** | **9.00%** |

The marginal cost study provides estimates of the marginal cost of each element of service, time-differentiated for elements with costs that vary with time, and by customer class. Marginal cost revenues were computed by multiplying the 2006 marginal cost of each element of service by estimates of the corresponding units for each class. For purposes of economic efficiency, each class (and ideally each customer) should pay revenues sufficient to cover, at a minimum, its marginal cost of service. **Figure 1** emphasizes that domestic customers and BL&P employees do not meet this test.

**Figure 1 – Comparison of Marginal Cost Revenues and Current Revenues**




The sum of class marginal cost revenues total about 75 percent of the total 2005 revenue requirement, as defined using historical costs for rate base and depreciation and our estimate of BL&P's current cost of capital. To use marginal costs as the basis for class revenue allocation, some method must be used to close this gap. Lacking information on the relative price elasticity of demand by each customer class, we closed the gap between 2005 total revenue requirement and 2006 marginal cost revenues using the "equi-proportional marginal cost" (EPMC) approach. Each class's marginal cost revenues were adjusted by the constant percentage necessary to reach the overall revenue requirement. This approach implicitly treats each class as having the same price elasticity.

It is probably the case that business customers that compete with similar firms in other countries have a higher price elasticity of demand than business customers whose customers are primarily within the country, and than residential customers. Thus, there is probably a legitimate argument that, to maximize efficiency, businesses competing in world markets should be allocated a smaller share of the marginal cost revenue gap than indicated by the EPMC approach. However, in this project we have not been asked to identify such customers or to estimate their relative elasticities of demand.

**Table 14** shows class marginal cost revenues and EPMC revenues by class, as well as the rate changes necessary to produce EPMC class revenues.

**Table 14 — Marginal Cost Revenues and EPMC Revenues by Class**

| | 2005 Revenues | 2006 Marginal Cost Revenues | (EPMC) Equiproportional Marginal Cost at 10.40% ROR | Rate Change Required to Match EPMC Class Revenue at 10.40% ROR |
|---|---|---|---|---|
| | | (BB$) | | |
| Domestic Service | 105,611,295 | 108,135,639 | 145,109,863 | 37.4% |
| Employee | 563,735 | 752,064 | 1,009,213 | 79.0% |
| General Service | 18,117,802 | 16,377,121 | 21,976,859 | 21.3% |
| Secondary Voltage Power | 125,654,335 | 91,180,965 | 122,357,971 | -2.6% |
| Large power | 83,741,260 | 55,237,943 | 74,125,150 | -11.5% |
| Street Lights | 3,871,653 | 2,490,552 | 3,342,132 | -13.7% |
| **Total** | **337,560,080** | **274,174,283** | **367,921,189** | **9.0%** |

**Table 15** provides a comparison of current class revenues compared to the various notions of cost-based class revenues described above.

***Table 15 – 2005 Revenues Versus Costs by Class***

| | 2005 Revenues | Embedded Cost Study 2005 Realized | Embedded Cost Study 10.40% ROR | 2006 Marginal Cost Revenues | (EPMC) Equiproportional Marginal Cost 10.40% ROR |
|---|---|---|---|---|---|
| | | | (BBD$) | | |
| | (1) | (2) | (3) | (4) | (5) |
| Domestic Service | 105,611,295 | 124,070,000 | 142,289,176 | 108,135,639 | 145,109,863 |
| Employee | 563,735 | 725,000 | 849,302 | 752,064 | 1,009,213 |
| General Service | 18,117,802 | 17,569,000 | 18,889,084 | 16,377,121 | 21,976,859 |
| Secondary Voltage Power | 125,654,335 | 116,006,000 | 123,239,605 | 91,180,965 | 122,357,971 |
| Large power | 83,741,260 | 73,260,000 | 75,594,285 | 55,237,943 | 74,125,150 |
| Street Lights | 3,871,653 | 5,909,000 | 7,059,737 | 2,490,552 | 3,342,132 |
| Total | 337,560,080 | 337,539,000 | 367,921,189 | 274,174,283 | 367,921,189 |

Current revenues from the domestic class (and particularly from BL&P employees, who receive an employee discount) fall short of cost of service by any measure. General service customers today are paying more than their allocated share of embedded costs at BL&P's 2005 earned rate of return and more than marginal cost revenues, but less than embedded cost using estimated current cost of capital and significantly less than EPMC revenues. Secondary voltage power and large power classes are paying more than any of these measures of cost. By any standard, domestic customers and employees are being subsidized by the larger commercial and industrial customers.

Marginal generation costs (energy and generation capacity) vary from year to year as BL&P adds and retires generating units and as load grows. Because class revenue and rate structure policies should take into account cost relationships for more than one year, we also computed marginal cost revenues by class using 2007-2010 marginal costs (stated in 2006 BBD$, and using 2005 consumption levels). This forward look at marginal cost revenues is shown in **Table 16.**

**Table 16 – Marginal Cost Revenue by Year**

| | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|
| | | | (2006 BBD$) | | |
| | (1) | (2) | (3) | (4) | (5) |
| Domestic Service | 108,135,639 | 107,940,347 | 104,602,399 | 99,231,405 | 97,224,197 |
| Employee | 752,064 | 750,566 | 724,957 | 683,750 | 668,351 |
| General Service | 16,377,121 | 16,368,309 | 15,831,835 | 14,846,211 | 14,551,995 |
| Secondary Voltage Power | 91,180,965 | 91,210,337 | 87,262,943 | 79,499,938 | 77,453,526 |
| Large power | 55,237,943 | 54,368,002 | 51,856,397 | 47,390,016 | 45,978,271 |
| Street Lights | 2,490,552 | 2,483,770 | 2,450,152 | 2,422,158 | 2,395,890 |
| Total | 274,174,283 | 273,121,331 | 262,728,682 | 244,073,479 | 238,272,231 |

| | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|
| | | | (Percent) | | |
| | (1) | (2) | (3) | (4) | (5) |
| Domestic Service | 39.44% | 39.52% | 39.81% | 40.66% | 40.80% |
| Employee | 0.27% | 0.27% | 0.28% | 0.28% | 0.28% |
| General Service | 5.97% | 5.99% | 6.03% | 6.08% | 6.11% |
| Secondary Voltage Power | 33.26% | 33.40% | 33.21% | 32.57% | 32.51% |
| Large power | 20.15% | 19.91% | 19.74% | 19.42% | 19.30% |
| Street Lights | 0.91% | 0.91% | 0.93% | 0.99% | 1.01% |

The class shares of the marginal cost revenue are relatively stable over this period. However, when class revenues are set in the next rate case, it would be useful to calculate class marginal cost revenues over the period the rates are expected to be in effect.

**Recommendations:**

Our preliminary estimates of BL&P's current cost of capital suggest that a significant overall rate increase may be warranted. However, our review did not cover other elements of the revenue requirement. We recommend that until a full rate case is conducted, any adjustments to class revenue allocations (such as those that might be undertaken in a revenue neutral rate adjustment) be conservative.

It is clear, though, that whether the benchmark is embedded costs at today's rate of return, embedded costs at BL&P's current estimated cost of capital, marginal cost revenues, or EPMC revenues, rates for domestic customers and employees are significantly below cost, and rates for SVP and LP customers are above cost. We recommend that when rates are changed, a transition period to move these class' revenues to more appropriate levels be considered. We also recommend that FTC begin a public information program to educate stakeholders about the importance of and need for rate restructuring, and to prepare customers for the rate changes that are likely to be required.

# VI. Rate Design within Classes

## A. Cost Basis

Although use of marginal costs to set class revenue requirements is not universal, in jurisdictions where efficiency is an important objective, the structure of marginal costs is typically used to establish the structure of rates within classes, albeit with adjustments necessary to meet other rate objectives. Use of marginal cost information is particularly important when TOU rates are being developed, because marginal cost information is necessary to design seasonal and peak/off-peak price differentials that will help consumers make efficient decisions about whether to shift load from peak to off-peak, and whether to invest in new practices or equipment that will allow them to reduce consumption in high cost periods or increase consumption in low cost periods. A marginal cost-based rate structure is also important when consumers are considering whether to invest in self-generation that will require backup by the utility. We recommend that electricity rate structures for Barbados be developed by starting with the structure of marginal costs, and then making adjustments necessary to achieve other objectives, including customer understanding and feasibility of implementation.

## B. Cost-Reflective Rate Structures

**Tables 17 through 19** summarize the components of marginal cost.

**Table 17 – Summary of 2006 Marginal Generation, Transmission, Substation and Feeder Costs**

| | | Peak | Off-Peak |
|---|---|---|---|
| | | (2006 BBD$) | |
| | | (1) | (2) |
| | Large Power | | |
| (1) | Energy (per kWh) | $0.2946 | $0.2038 |
| (2) | Generation Capacity (per peak period kW-mo.) | $1.30 | |
| (3) | Transmission (per peak period kW-mo.) | $1.66 | |
| (4) | Distribution Substation (per peak period kW-mo.) | $4.03 | |
| | Total per kW | $6.99 | |
| | Secondary Voltage | | |
| (5) | Energy (per kWh) | $0.3033 | $0.2085 |
| (6) | Generation Capacity (per peak period kW-mo.) | $1.32 | |
| (7) | Transmission (per peak period kW-mo.) | $1.69 | |
| (8) | Distribution Substation (per peak period kW-mo.) | $4.10 | |
| | Total per kW | $7.11 | |
| | General Service | | |
| (9) | Energy (per kWh) | $0.3033 | $0.2085 |
| (10) | Generation Capacity (per peak period kW-mo.) | $1.32 | |
| (11) | Transmission (per peak period kW-mo.) | $1.69 | |
| (12) | Distribution Substation (per peak period kW-mo.) | $4.10 | |
| | Total per kW | $7.11 | |
| | Domestic | | |
| (13) | Energy (per kWh) | $0.3033 | $0.2085 |
| (14) | Generation Capacity (per peak period kW-mo.) | $1.32 | |
| (15) | Transmission (per peak period kW-mo.) | $1.69 | |
| (16) | Distribution Substation (per peak period kW-mo.) | $4.10 | |
| | Total per kW | $7.11 | |
| | Street Lights | | |
| (17) | Energy (per kWh) | $0.3033 | $0.2085 |
| (18) | Generation Capacity (per peak period kW-mo.) | NA | |
| (19) | Transmission (per peak period kW-mo.) | NA | |
| (20) | Distribution Substation (per peak period kW-mo.) | NA | |
| | Total per kW | NA | |

**Table 18 – Summary of Marginal Distribution Facility and Customer Costs**

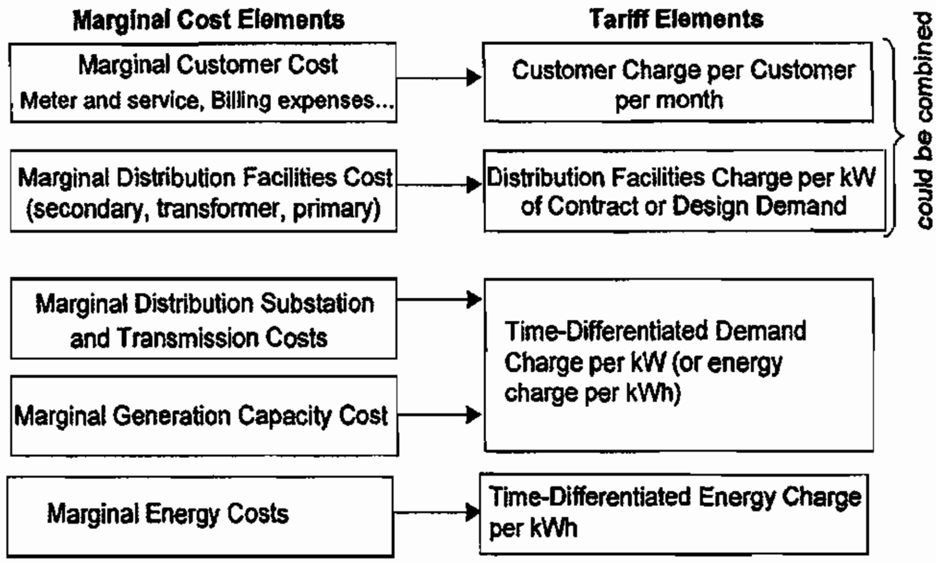
| | Customer Class | Monthly Facility Cost per kVA of Design Demand | Estimate of Typical Design Demand by Customer | Monthly Facility Cost per Customer | Monthly Marginal Customer Cost per Customer |
|---|---|---|---|---|---|
| | | (BBD$/kVA) | (kVA) | (BBD$/customer/mo.) | |
| | | (1) | (2) | (3) | (4) |
| | | | | (1)*(2) | |
| (1) | Domestic | $6.82 | 3.51 | $23.91 | $9.79 |
| (2) | General Service | 6.82 | 3.51 | 23.91 | $11.30 |
| (3) | Secondary | 3.19 | | | $14.20 |
| (4) | Large Power | 0.69 | | | $119.70 |

**Table 19 – Summary of Marginal Distribution Facility and Fixture Costs for Street Light**

| | Customer Class | Monthly Cost per Fixture | Monthly Facility Cost per kVA of Design Demand | Estimate of Typical Design Demand | Monthly Distribution Facility Cost per Fixture | TOTAL Monthly Cost Per Fixture |
|---|---|---|---|---|---|---|
| | | (BBD$) | (BBD$) | kVa | (BBD$) | (BBD$) |
| | | (1) | (2) | (3) | (4) | (5) |
| | | | | | (2)*(3) | (1)+(4) |
| (1) | 50 W HPS | $4.61 | $6.82 | 0.08 | $0.55 | $5.16 |
| (2) | 100 W HPS | $4.54 | 6.82 | 0.18 | $1.25 | $5.79 |

The major elements of marginal cost of service can be translated directly into rate structure, provided that metering and billing systems are adequate, as illustrated on **Figure 2**.

**Figure 2 – Marginal Cost and Rate Elements**




Time-differentiated charges to cover time-varying marginal costs of energy, generation capacity, and transmission and distribution substations are ideal, but the metering necessary for TOD rates is typically not cost-effective for small consumers. Seasonal rates can be implemented for all customers at low cost. However, in the case of BL&P, we found no significant seasonal differences in costs.

Traditional rate structures based on embedded costs typically recover capacity costs on the basis of a customer's maximum demand (either monthly or with some reference to previous months as well). This approach is consistent with the nature of embedded cost studies, which attribute capacity costs to a few peak hours of the year and allocated capacity costs on the basis of class contributions to one or more system peaks, or class non-coincident peaks. The resulting demand charges make allowance for the fact that all customers in the class do not impose their peaks in the same hour by applying coincidence factors to derive the demand charges, or by simply dividing the allocated costs by the sum of the billing demands for the class.

Marginal cost studies recognize that there is some probability of non-zero marginal capacity costs in many hours, not just in what will turn out, after the fact, to be the peak hour. A pure marginal cost-based rate structure identifies capacity costs (per kWh) in each hour, and aggregates hours into narrow pricing periods with similar costs. Such a rate structure recovers capacity costs on the basis of energy consumed in a number of fairly narrow pricing periods, rather than in demand charges.

There are several advantages to recovering capacity costs on an energy basis. To the extent that a customer's maximum demand occurs in an hour that is not a critical hour, demand charges provide an inefficient price signal. Furthermore, once a customer has set what he expects to be his peak demand for the billing period, he has no incentive to control loads in other hours, although doing so might reduce costs or improve reliability of the system. This effect is particularly strong in BL&P's current rates, in which the customer pays demand charges based on the highest monthly demand in the past 12 months (a 12-month "ratchet"), rather than on the highest demand during the billing month. In addition, many customers do not understand demand charges, or how to control their bills by controlling their maximum demands.

If the objective of giving economically efficient price signals to each customer is given high weight, recovery of capacity costs on a time-differentiated per-kWh basis makes sense. A utility that is interconnected with other utilities has the opportunity to buy and sell energy and capacity in the wholesale market. Such a utility's capacity costs are not as "fixed" as those of a utility, such as BL&P, with no access to a wholesale market. BL&P must install sufficient capacity to meet its customers expected demands, and cannot rely on a wholesale market to purchase more or sell excess in the case of forecasting errors. Thus, it may be more appropriate for BL&P to continue to recover capacity costs in ratcheted demand charges, preferably time-differentiated.

Reconciling marginal costs to a rate structure that recovers the allocated class revenue requirement requires adjusting some charges away from marginal cost. Because consumption is least affected by changes in fixed charges, the most efficient reconciliation method is to adjust the monthly fixed charges, provided that doing so does not affect the total bill so dramatically that it leads to inefficient decisions to connect or disconnect from the grid. In some cases the size of the increase in the fixed charge is so great, that it would produce unacceptable bill impacts for small customers. In that case, a portion of the adjustment can be made in other charges. Blocked energy charges with the adjustment in the first block and a second block set at marginal cost retain the efficient price signal for all consumers with consumption large enough to get into the second block. When time-differentiated energy and demand charges must be adjusted away from marginal cost, the goal should be to reflect the relative size of demand and energy charges,[51] and maintain the marginal cost differentials between peak and off-peak charges.

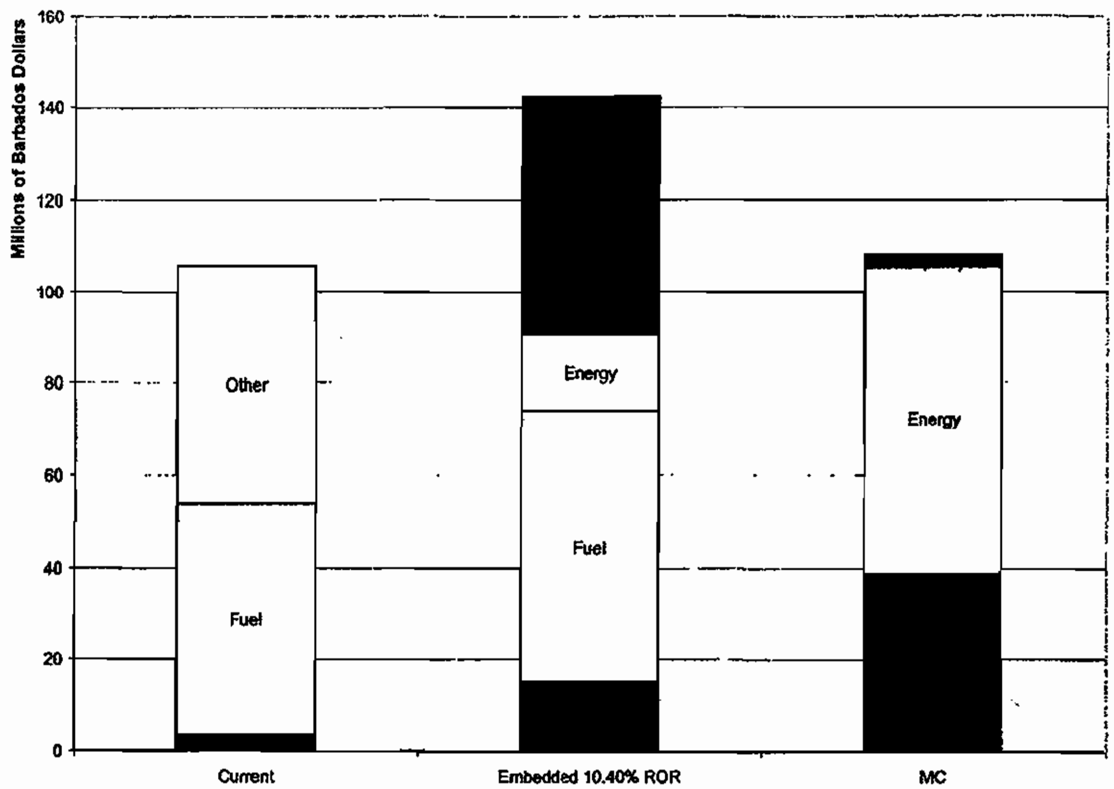
## C. Structure of Marginal Costs, Embedded Costs and Current Rates, by Class

The figures below show a comparison of the structure of marginal cost revenues and current rate revenues, by class. Although we do not recommend using embedded costs for rate structure, the embedded cost structure is provided as well. These figures were developed by calculating the

[51] Unless there is information suggesting that customers are more/less price responsive to energy than to demand charges. In that case, the larger adjustment should be made to the less elastic rate component.

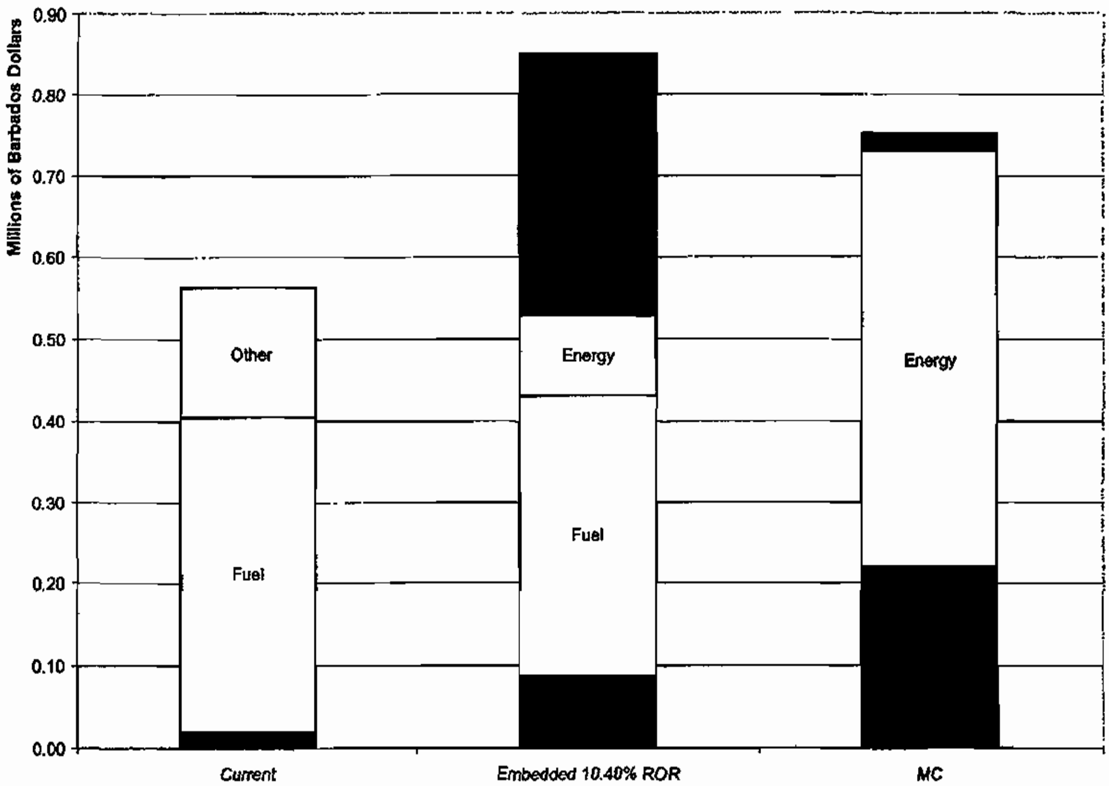
various components of marginal cost and embedded cost revenue (using estimated current cost of capital), and the components of current revenue by rate element. The facilities costs (purple) shown in the marginal cost bars cover costs of local distribution facilities that are included in the capacity costs (pink) in the embedded cost bars and the current rate bars (where applicable).

**Figure 3 – Domestic Rates and Costs by Component**



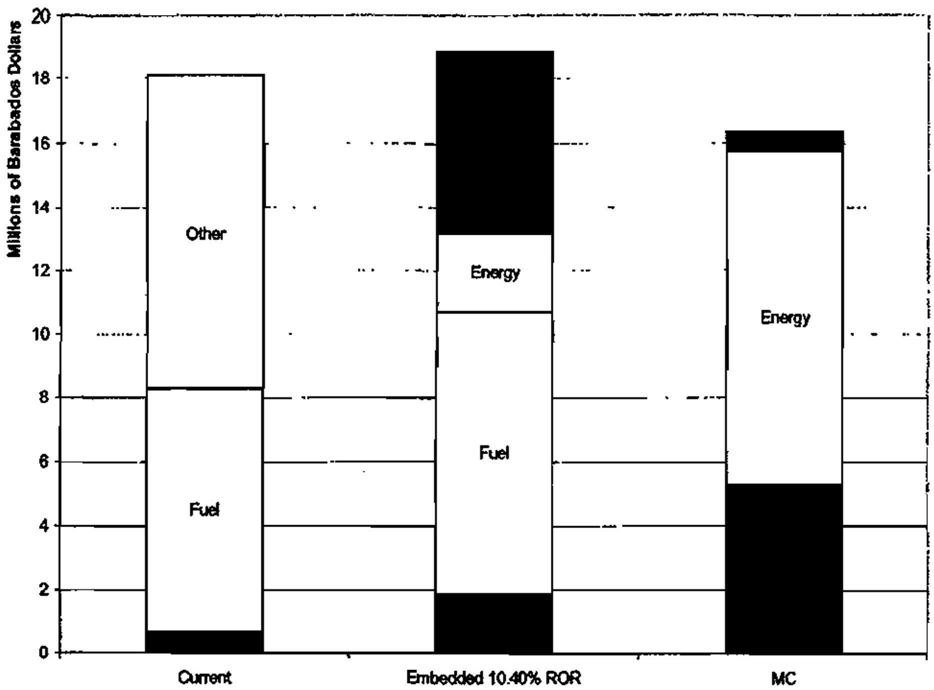

The bulk of domestic the revenues are currently collected in the base kWh charge (other) and the fuel adjustment charge. A significant portion of the marginal costs are customer-related and related to the local distribution system. Both the marginal and embedded cost results would justify an increase in the fixed charges for domestic customers.

**Figure 4 – Employee Rates and Costs by Component**



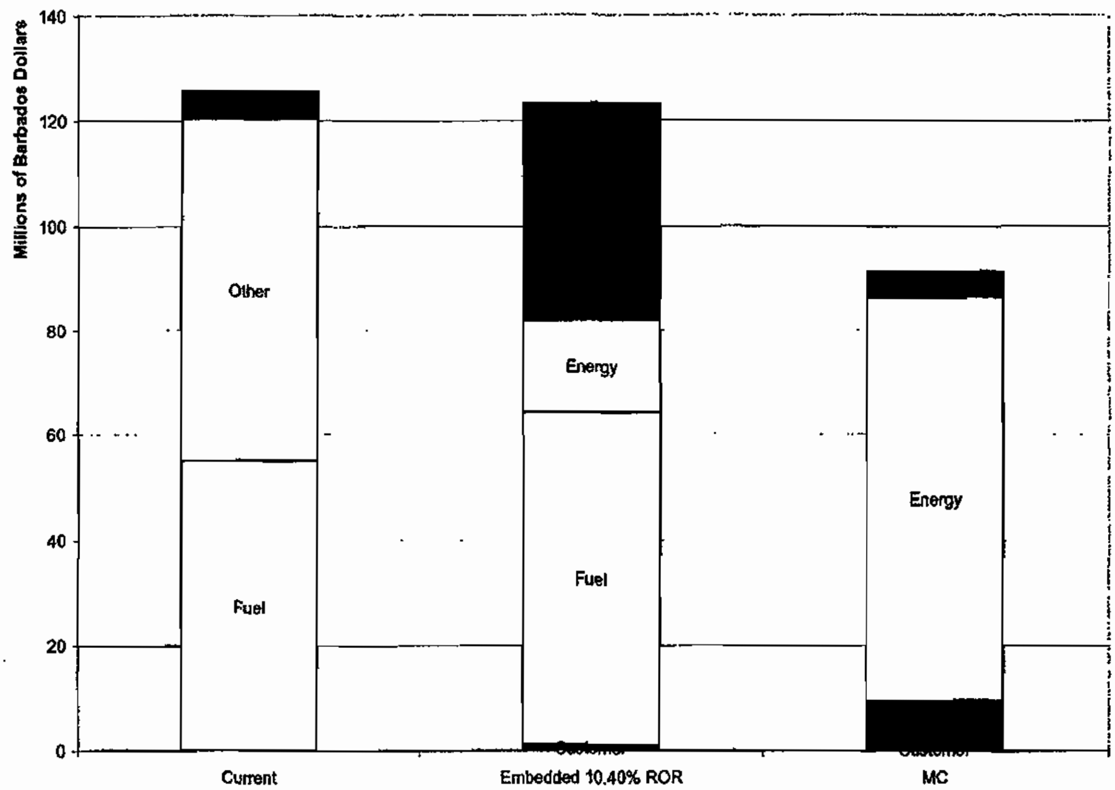

Service for employees is similar to the domestic class, though the average use is somewhat higher than that for the domestic class. We discuss below possible options for improving the employee rate structure.

**Figure 5 – General Service Rates and Costs by Component**



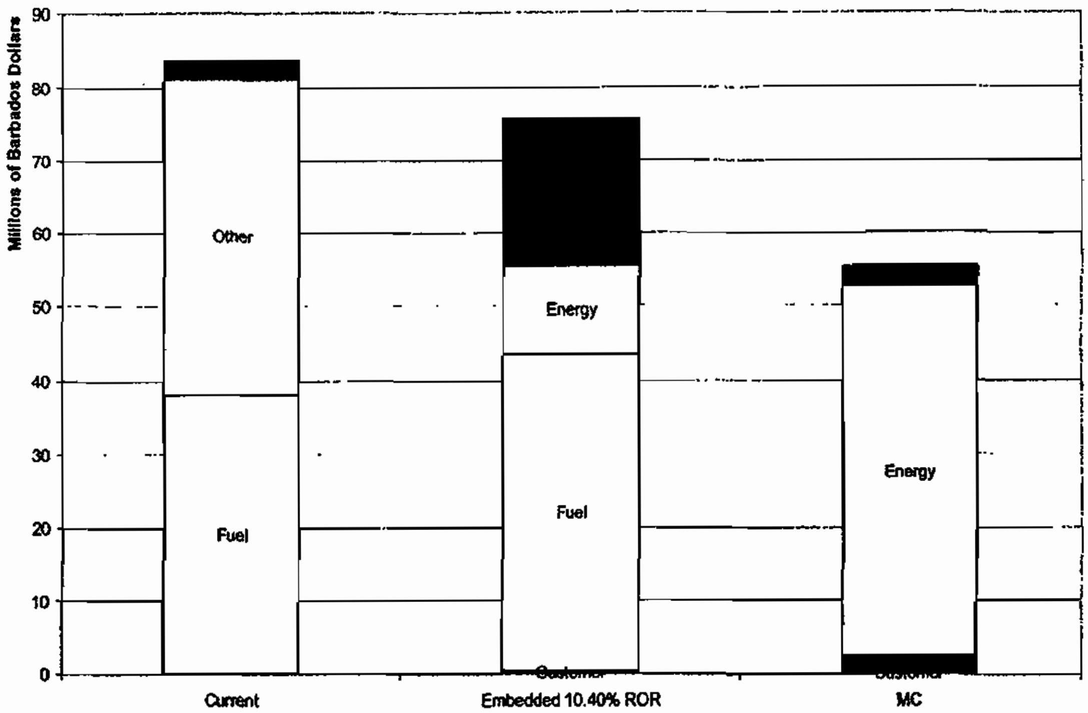

Both the marginal and embedded cost studies would justify higher fixed charges (customer and local facilities) for general service customers.

**Figure 6 – Secondary Voltage Power Rates and Costs by Component**




Under current secondary voltage power (SVP) rates, most of the revenues are collected through base and fuel adjustment per kWh charges. The rate includes a demand charge but it produces revenues below embedded capacity costs and approximately equal to marginal capacity costs, although not below EPMC marginal capacity costs if part of the revenue gap adjustment were made to marginal capacity costs. The marginal cost results would justify introduction of fixed charges to cover customer and local facilities costs. And reconciliation to class revenues would *justify an increase in demand charges.*

**Figure 7 – Large Power Rates and Costs by Component**




Under current large power (LP) rates, most of the revenues are collected through base and fuel adjustment per-kWh charges. The rate includes a demand charge but it produces revenues below embedded capacity costs and slightly below marginal capacity costs. The marginal cost results would justify introduction of fixed charges to cover facilities costs and higher demand charges.

**Rate structure recommendations:**

*Domestic and BL&P Employees:*

Under current domestic rates the most revenues are collected in the base energy kWh charge (which inclines slightly with number of kWh consumed per month) and the fuel adjustment charge. The marginal cost study shows that local distribution facilities and customer cost make up a significant portion of the domestic costs. The efficiency and fairness of the domestic rate structure would be improved by introducing a customer charge that covers marginal customer costs and a facilities charge per kVA that covers the marginal cost of local distribution facilities. Design demand for domestic customers ranges from less than 1 kVA to approximately 10 kVA, so, although it is a fixed component of the bill for individual customers, the facilities charge would be a small component of the bill for low use customers, who probably tend to be low income as well. If warranted, a lifeline feature could be introduced for low income families, by reducing or eliminating the two fixed components of the bill.

Introduction of a facilities charge per kVA of design demand would provide additional revenue stability for BL&P, because less revenue would be dependent on the level of kWh sales. Furthermore, use of a facilities charge is especially important to a utility in a resort area such as BL&P, as it assures year-round contribution to the cost of the distribution network from seasonal customers.

BL&P employees currently benefit from a subsidized per kWh rate. A more efficient mechanism for providing this benefit would be to convert it to a fixed credit on the bill, so that employees would see the same marginal price for kWh use as other domestic customers.

*General Service*

The typical general service customer is only slightly larger than the typical domestic customer. The combined efficiency and equity arguments for applying customer and facilities charges to the domestic customer class also apply to the general service class.

*SVP and LP*

As is the case for the other classes incorporating a customer charge and a design demand/contract demand charge in the SVP and LP rates would make the rate structures more cost reflective move the per-kWh recovery toward marginal energy cost and potentially reduce revenue volatility.

In SVP and LP rates the total kWh charges (fuel plus other) are substantially in excess of the marginal energy costs. This is an invitation to uneconomic bypass.[52]

Given the prevalence of self-generators in Barbados it may be appropriate to set demand charges above marginal capacity costs (perhaps by incorporating a portion of the marginal cost revenue gap in demand charges). The isolation of the BL&P system means that BL&P must maintain sufficient generation transmission and distribution substation capacity to serve self-generation customers when their units are out of service. There is no doubt significant diversity in the need for standby service due to technical outages; customers with generators are unlikely to experience mechanical breakdowns simultaneously. However high fuel prices or fuel supply disruptions could affect all these units, meaning that most customers with self-generation would need backup at the same time. For this reason we recommend that BL&P consider demand charges for SVP and LP that are higher than marginal capacity costs or implementation of a reservation charge for standby customers that recovers a portion of embedded capacity cost in excess of marginal capacity costs.

The marginal cost study identifies significant differences in marginal energy costs (peak cost is about 50 percent higher than off-peak) and all marginal capacity costs fall in the peak period defined as 9 am – 3 pm on weekdays. Although information on the likely responsiveness of BL&P customers to time-of-use rates is not currently available it is highly likely that LP and larger SVP customers would shift enough demand from peak to off-peak hours to justify the additional metering and billing costs associated with implementing TOU rates. For example we understand that the Water Authority a major BL&P customer is currently considering a major renovation of its facilities. Faced with TOU rates the Water Authority might redesign its system so that it can pump off peak thereby saving its own customers money on their water bills and freeing up BL&P capacity to serve other electricity customers in the peak period.

BL&P is gradually replacing electro-mechanical meters with electronic meters which can be configured to provide billing information for TOU rates. Although the current billing system may not be able to handle TOU rates many utilities use a separate billing system for TOU customers in such situations. Thus it may be feasible for BL&P to implement TOU rates for its largest customers in the near term.

[52] Uneconomic bypass results when customers choose an alternative supply of electricity (such as installing self-generation) that has a higher cost than the utility's true economic (marginal) cost of providing the same service.

*Optional interruptible rate for self-generators and other large customers*

Higher demand charges for self-generators may create a demand for optional interruptible rates. Self-generators willing to take backup service on an interruptible basis, could pay lower demand charges to compensate for their willingness to have service curtailed in hours when capacity is constrained. Such interruptible arrangements should include a several-year-long contract to keep customers from shifting on and off the interruptible rate as BL&P's reserve margin changes. Other large customers might be interested in an interruptible option for a portion of their loads as well.

## D. Notes on Implementation Strategies

Some of these proposals could be put in place quickly; others, specifically time of use rates for the largest customers would require new meter equipment and billing systems, although we understand that BL&P is in the process of acquiring a new, highly capable billing system.

Major changes in rate design (both class allocations and rate structures) may require a transition period, or other mechanisms to protect adversely affected customers from unacceptable bill increases until they have an opportunity to adjust to the new rates. Lifeline rates with an income eligibility requirement are one way to protect low-income customers. Bill limiters (which cap the percentage increase in bill for a specified period) are another transition mechanism.

**Recommendations on implementation:**

Before a major rate restructuring is made, it is important to develop accurate forecasts of changes in customer usage levels and patterns, changes in utility costs resulting from load changes, and resulting revenues. Phasing in new rate structure is one way to limit the size of unanticipated effects when accurate forecasts are unavailable.

# VII. Demand Forecasting and System Planning Review

One of our tasks in this project was to assess the appropriateness of BL&P's methods and tools for forecasting load and planning system expansion. We based our analysis on a brief written summary of methods, prepared by BL&P, and discussions with company engineers.[53] Our impression is that BL&P is using appropriate methods for both demand forecasting and system planning, although additional quantitative risk and options analysis might be useful.

## A. Demand Forecasting

The method of demand forecasting employed by BL&P is a simple extrapolation of historical levels of demand growth. A base case level of demand growth of 4 percent of peak load per year is used in it most recent forecast, with low and high cases of 2 percent and 6 percent respectively. Transmission and Distribution system losses have been quite stable, and in line with the historical average and with the effect of recent system upgrades, a losses factor of 7.3 percent has been assumed. In line with the historical average, a constant system load factor of 71.5 percent has been assumed.

Given the context of a small system with peak load of around 150 MW, with load growth of the levels described, and given the economic new generator size of between 20 MW and 30 MW, NERA is of the opinion that the simple extrapolation method of forecasting load growth is appropriate for BL&P for purposes of generation planning.

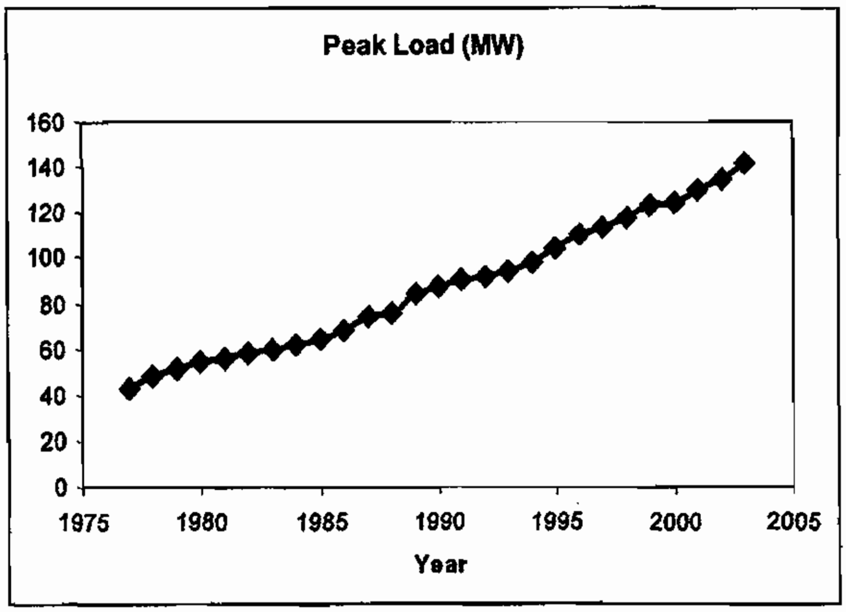
We concur that, in a small system such as Barbados, a more sophisticated method of "top-down" forecasting of load growth would add little value and would be likely to add little in the way of meaningful forecast accuracy. However, we believe that any significant and non-typical load additions could justify a "bottom-up" adjustment to the simple forecast; for example, any exceptional one-off addition or withdrawal of an energy-intensive industry would justify a one-off adjustment to the simple extrapolation.

Regarding the impact of load forecast error on generation planning decisions, we expect that the small absolute values of load growth relative to the economic size of an efficient new unit means that load forecast error, and the simplified method of forecasting load in particular, should have a relatively low impact on the ability of BL&P to maintain generation adequacy.

[53] "Barbados Light & Power Company Limited - System Expansion Planning," March 8, 2006.

We base this conclusion on a comparison of the level of load growth, and the uncertainty around that level, to the economic new generator size. Figure 8 shows load growth in Barbados from 1977 to 2003. Peak load grew by the largest amount, in percentage terms, in 1978 (approximately 12 percent) and by the least amount, in percentage terms, in 1992, 1993, and 2000 (approximately 2 percent). Given this range of extremes (10 percent of load) and the current level of peak load of around 150 MW, it would be reasonable to assume that a forecast error of 15 MW (10 percent of 150 MW) would be an extreme outcome. This extreme outcome could be covered twice over by the accelerated development of a single new efficient unit (of 30 MW). As load growth is normally assumed to be about 4 percent (6 MW) per annum, such an extreme outcome could therefore bring forward the construction of such a unit by up to 2 ½ years (15 divided by 6). So long as a reasonable state of readiness in anticipation of changing conditions continually exists, and planning arrangements are continually in place for the next required new unit of the system so that the next new unit can be installed relatively quickly if required, this should represent an acceptable level of exposure to demand forecast error.

**Figure 8 – Barbados Load Growth 1977 - 2003**




**Recommendation:**

We recommend that any significant and non-typical load additions be reflected with a "bottom-up" adjustment to the simple forecast. For example, any exceptional one-off addition or withdrawal of an energy-intensive industry would justify a one-off adjustment to the simple extrapolation of historical load growth.

## B. System Planning

System planning (generation adequacy planning) for a small system like Barbados can be fundamentally different from planning for a large interconnected system. In a large system, generation adequacy is defined by adherence to a predefined installed reserve margin. The installed reserve margin, in turn, is pre-calculated so as to represent an acceptable Loss of Load Probability (LOLP) standard. In a small system, by way of contrast, the separation of the installed reserve requirement and the LOLP standard is less meaningful because each new unit that joins the system is a significant percentage of the overall generating fleet. The new unit that joins could form the first (or perhaps second) contingency event on the system. Accordingly, the size of the next generator that joins is itself a key determinant of the resultant LOLP.

Another complication for system planning in Barbados is the extreme uncertainty of fuel prices and new fuel supplies. BL&P imports virtually all fuel used in its generators and is subject to fluctuations in world fuel prices. Furthermore, the possibility of a natural gas pipeline's being built to Barbados means that BL&P needs to take into account a possible future when gas-fired generators could be used.

The objective of the generation planning process should be to reach the least-cost expansion plan necessary to achieve the LOLP target. At an even higher level of abstraction, the resultant plan should be of least cost to the electricity consumers Barbados, taking into account the full costs of electricity production, and the full economic costs of any electricity shortfall.

Relevant factors to be taken into account in the generation expansion process include: load growth (both energy and peak load); forced plant retirements; unit availabilities, operating costs for all units, environmental costs, the opportunity costs of sites, a representation of the Value of Lost Load (VOLL) and a reasonable modeling representation of real-time system dynamics regarding how installed capacity is converted into available capacity operationally (through use of spinning reserve and other unit capabilities) and of how other real-time reliability tools (such as load shedding) are implemented.

The decision variables to be taken into account in the generation expansion process should include: repowering options; economic plant retirements (for example to free up a site for a larger plant or benefit from efficient modern fuel efficiency performance); availability of natural gas; and a range of viable new unit construction options. All options should be proven technologies, have known costs, have available siting, and meet environmental and other technical standards.

The solution obtained through the generation planning process should be robust – i.e. it should be the case that when alternative reasonable assumptions are provided (such as alternative load forecasts, discussed above) that the same generation plan is produced – or at least one very close to it where, for example, the date of construction of new units may be accelerated or decelerated slightly.

NERA has conducted a limited review of the generation expansion process performed by BL&P and we conclude that the relevant planning criteria, relevant parameters, and relevant decision variables are taken into consideration in that process. We have not tested the robustness of solutions obtained; however, we note that BL&P identifies solution robustness as a key criterion.

We note that BL&P states that "risk is not explicitly dealt with in the 'least cost' planning process". However "Risk is introduced in the planning process by using Monte Carlo models to represent the various uncertainties (fuel prices, technological obsolescence, etc)"[54] and that the company does have access to Monte Carlo models such as @Risk and Crystal Ball. NERA recommends that BL&P investigate the expanded use of these models. Developing the system expansion plan in a probabilistic manner would calculate the least cost associated with an LOLP target within a single integrated model run, in which the LOLP associated with a particular generation configuration was also calculated. This model would probabilistically estimate the LOLP and VOLL associated with each candidate expansion plan by Monte Carlo analysis, together with the expected cost – and the range around that expected cost – associated with each candidate expansion plan.

We understand that BL&P ignores the impact of fuel taxes in its system planning process. Because the pre-tax cost of imported fuels is the true cost to the economy of Barbados, this BL&P policy means that the objective of generation planning is to minimize costs to the country, not necessarily to minimize costs to the Company. We believe that this is a socially-responsible approach.

We also understand that the target level of reliability (24 hours per year) used by BL&P has not been reviewed in many years. As customer use of electricity changes (*e.g.,* use of electronic equipment that is sensitive to outages) and the cost of adding reserves changes over time, VOLL and the optimal LOLP can also change. We recommend that BL&P undertake a new analysis to verify that this reliability target still represents the least-cost trade-off between the cost of unserved energy and the total cost of energy production.

[54] Quotations are from "Barbados Light & Power Company Limited - System Expansion Planning," March 8, 2006.

| **Recommendations:** |
| --- |
| We recommend that BL&P make more extensive use of the probabilistic features of its generation planning models and re-evaluate its reliability target. |

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# A

# Appendix A: Asset Base Methods in Europe

The following note summarizes the Regulatory Asset Base (RAB) methods used by European regulators in establishing required revenues for the regulated companies in electricity, gas, water and telecommunication sectors in Belgium, France, Germany, Italy, Netherlands, Spain and United Kingdom.

## A. Belgium

Tariffs in energy sector (electricity and gas transmission and distribution) are approved annually and must cover "reasonable costs " and allow firm to earn a "fair" margin. The initial RAB was determined on the basis of the replacement cost. The value of RAB is recalculated from investments and depreciation by a formula. RAB is not inflated or indexed. For electricity transmission and gas transmission and distribution, RAB includes working capital. The rate of return applied is nominal post tax.[1]

The water utility is state owned and RAB methodology is not applicable.

In the telecoms sector, the asset base is reported in regulatory accounts and audited by an independent firm, current cost accounting is used for the interconnection and historic cost accounting for unbundling.

## B. France

Tariffs in the energy sector are set for 12-18 months on a cost-plus basis. RAB in the electricity sector is based on the net book value of the assets and the working capital. The applicable rate of return is nominal pre-tax.[2]

In the gas sector, initial value of RAB is determined either with reference to the current costs (gas distribution and some types of assets in the gas transmission), or by some special rule (gas transmission assets). The asset value for each year is inflated by forecast inflation and the real pre-tax rate of return is applied. The difference between the forecast and actual rate of inflation is compensated in the following period.

The costs of provision of water services are based on the privately negotiated contracts with individual municipalities and the RAB does not apply.

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[1] The Lignes Directrices - the guidelines for calculating the fair margin applicable to operators of transport ands distribution networks for gas ((B) 030618-CDC-218) and electricity ((B) 030618-CDC-219). They were both published by the CREG on 18 June 2003 and apply to all companies in these activities.

[2] Commission de Regulation de L'Energie. URL:
http://www.cre.fr/fr/ressources/consultationspubliques/consultationspubliques_consultation.jsp?idDoc=1732
http://www.cre.fr/fr/ressources/consultationspubliques/consultationspubliques_consultation.jsp?idDoc=1246
http://www.cre.fr/uk/ressources/consultationspubliques/consultationspubliques_consultation.jsp?idDoc=1609

France telecom RAB is based on Current Cost Accounting. The asset base is reported in regulatory accounts and audited by an independent firm.

## C. Germany

Germany does not currently have an independent energy sector regulatory authority with rule-making powers in both the electricity and gas industry. Instead, there are associated agreements concluded between several energy industry groups in electricity and gas. For the rate base purposes, assets are valued using a company's financial accounts as a starting point. Historic cost accounting is used for valuing assets financed by debt, and asset-type-specific indexation is used for valuing equity-financed investments.[3]

In the water sector prices are supervised by the Federal Cartel Office but otherwise not regulated.

For Deutsche Telekom, RAB is based on forward-looking costs.

## D. Italy

In 1997 the value of electricity transmission and distribution assets was set equal to the replacement cost of assets included in the 1994 balance sheet, adjusted for inflation and depreciation. For the 2004-2007 regulatory period, the 1997 asset value is updated by taking into account inflation, depreciation and net investments.[4] The real pre-tax rate of return is applied to net value of assets.

In the gas sector, Assets included in the RAB are valued in Current Cost Accounts (CCA) terms, using the method of historical costs indexed by inflation.[5] The real pre-tax rate of return is applied.

In the water sector RAB includes all assets used in the provision of water valued at historic costs, without indexation. Remuneration on capital is 7% but rules do not specify whether this is real or nominal, pre- or post-tax.

Assets included in the RAB of Telecom Italia are reported in its regulatory accounts and audited by an independent firm. From FY 2001, the assets are valued in Current Cost Accounting terms, before that, the Historic Cost Accounting was used.

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[3] Association of German Network Operators. URL: http://www.vdn-berlin.de/global/downloads/Publikationen/vv2plus_engl.pdf

[4] l'Autorità per L'Energia Elettrica e il Gas. URL: www.autorita.energia.it

[5] This asset valuation method applies only to companies with audited annual accounts since before 1991. It was introduced by the AEEG Delibera 122/02, after the Regional Court of Lombardia (TAR) declared void some technical details of the previous methodology contained in Delibera 237/00. For companies that do not have audited accounts or that have produced audited accounts only since 1991 the previous methodology applies, according to which the value of assets of each distribution company is a function of the number of customers, the population in each area, the network length and the amount of gas distributed in the previous year.

## E. Netherlands

For electricity, the setting of tariffs in the first regulatory period (2000 - 2003) was determined by the 1998 Electricity Act which states that initial tariffs for 2000 must be based on those of 1996. 2000 tariffs were therefore set at 1996 tariffs corrected for exogenous factors. In order to ensure that the RAB was consistent with the value of the assets based on these fixed prices, their value was set at the discounted value of future free cash flows permitted within the regulatory regime. RAB is updated annually by adding the costs of efficient investments, subtracting depreciation and controlling for the CPI. The regulator sets a nominal post tax WACC, but in calculation of revenue requirements applies a real WACC based on inflation rate of 2.2% per annum.[6]

In the gas transmission, the basis for tariff calculation is economic cost: this includes cost of capital, depreciation of invested capital and operating costs. The level of invested capital is determined based on historic cost net of depreciation and excluding goodwill.

In the gas distribution sector the price cap regulation was introduced in 2002 according to the model used in the electricity sector.

Water sector in Netherlands is operating on a non-profit principle and the rate base methodology does not apply.

Telecom regulation is based on the Current Cost Accounting with application of a real rate of return.

## F. Spain

The Spanish experience in the transmission regulation illustrates two alternative approaches to setting allowed revenues in the electricity transmission business. Under the first framework, RAB was derived by applying standard operating and investments costs defined by the Government to the specific characteristics of the assets. Under the current system, allowed revenues for transmission and distribution are updated using an RPI-X formula and the base-year revenues fixed in 1998 through an agreement between the Government and the utilities.

Private provision of water and wastewater services is predominantly based on concessions or management contracts. The concept of RAB is therefore not applicable.

The regulatory asset base of Telefonica is set by the regulator based on market value given by an independent consultant. The real rate of return is applied.

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[6] Dte. Guidelines for price cap regulation of the Dutch electricity sector in the period from 2000 – 2009, February 2000; Dte website http://www.dte.nl/;

## G. UK

Electricity transmission: NGC's RAB was first set out publicly on the basis of the company's stock market value on flotation in 1995. It has subsequently been updated by adding actual investment at cost and deducting depreciation. All these components are indexed to inflation (RPI).[7]

The regulatory asset values for the electricity distribution companies were determined using an indexed historical cost approach with special values for pre-privatisation assets.[8]

Gas transmission: Pre-1992 assets are valued using a version of acquisition cost valuation. Assets acquired from 1992 onwards are valued at original cost, inflated by the RPI. Revaluation is calculated by adding capex, subtracting depreciation, and updating the result in line with changes in the RPI.[9]

Gas distribution: Ofgem set the RAB for each regional distribution network at the level consistent with current charges, in order to minimise "tariff shock". Revaluation is calculated by adding capex, subtracting depreciation, and updating the result in line with changes in the RPI.[10]

The real rate of return is applied to the RAB in the electricity sector.

In the water sector regulator uses the Regulatory Capital Value. Initial asset valuation at privatisation was based on expected cash flows in the absence of privatisation... In 1994 assets were revalued based on the average trading values adjusted for unexpected gains and losses from land sales, impact of cash injections, and unexpected capital expenditure. Annual adjustments

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[7] Ofgem. URL: www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/1610_ngcpc02.pdf

[8] Ofwat. URL: www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/1181_pest.pdf

[9] Ofgem, various documents; "Review of Transco's price control from 2002: Final Proposals", Ofgem, September 2001 (http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/315_26sep01_pub1.pdf) and "Review of Transco's price control from 2002 Update paper (http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/318_20nov00.pdf)", Ofgem, November 2000. "Transco's National Transmission System, Review of System Operator incentives 2002-7, Proposals Document, February 2004" (http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/5821_SO_incentives_proposals_transco_%20Feb04.pdf) ..

[10] Ogem. "Separation of Transco's distribution price control Initial consultation document", Ofgem July 2002 (http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/246_11july02.pdf), "Separation of Transco's distribution price control: Final proposals", Ofgem, June 2003 (http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/3462_38sep_tdp.pdf), and "Gas Distribution Price Controls", Ofgem open letter posted on Ofgem website 16/3/04 (http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/6483_5604Openletter_GasDistributionPriceControl.pdf.)

are also made to RCV based on RPI, capex, depreciation, infrastructure renewals, and land disposal. The real rate of return is applied.[11]

When setting price controls in the telecoms sector the regulatory asset base is determined on the basis of the forward-looking replacement cost estimates.

[11] Ofwat (2002) "Approach to Depreciation for the Periodic Review 2004: A consultation Paper" (http://www.ofwat.gov.uk/aptrix/ofwat/publish.nsf/AttachmentsByTitle/rd0502_conspaper.pdf/$FILE/rd0502_conspaper.pdf), Ofwat (2003) "Setting Water and Sewerage Price Limits for 2005-10: Framework and Approach. Summary of Consultation Responses and our Conclusions" (http://www.ofwat.gov.uk/aptrix/ofwat/publish.nsf/Content/pr04_responses_summary270303).

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# Barbados Light & Power Company, Ltd.

## Embedded Costs of Electricity Service

[redacted]

*Prepared for the*

**Fair Trading Commission of Barbados**

**by**

**Amparo D. Nieto**

**April 2006**

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# Barbados Light & Power Company, Ltd.
# Embedded Costs of Electricity Service

## I. Introduction

As part of an assignment for the Fair Trading Commission of Barbados (FTC), and with assistance from Barbados Light & Power Company, Ltd. (BL&P), NERA Economic Consulting (NERA) prepared an Embedded Cost of Service study (ECOS) for BL&P's electricity service. The ECOS study functionalizes, classifies and allocates BL&P's revenue requirement to each of the electricity customer classes in Barbados. This report describes the methods used and summarizes the results of the analysis. The study uses 2005 as the test year.

An Embedded Cost of Service (COS) study begins with a utility's total costs (operating expenses, net plant, taxes, depreciation, etc.) for a particular test year, and uses a series of steps to identify each customer class' share of various cost components. The two main purposes of an embedded cost study are:

(1) Determine the overall rate of return the utility is earning in the particular test year, and the return on allocated rate base by class, to determine the degree of over/under recovery of allocated costs under existing tariffs.

(2) Calculate the new revenue requirement by class, which allows the utility to realize the overall allowed rate of return, and equalizes the rate of return contributed by each tariff.

There are many alternative methods for conducting the various steps of a COS study. There is no universally accepted method for classifying and allocating embedded costs. However, methods are usually chosen based on the characteristics and objectives of the specific utility being studied. Factors that often affect choice of methods include, among others: (1) the type of generation plant the utility has; (2) planning and operating constraints/policies; (3) the pattern of system loads across the year, including whether the system is winter-peaking, summer-peaking, or both; (4) the system load factor; and (5) the degree to which decision-makers want to reflect marginal cost or opportunity cost relationships in the COS study.

Since the last BL&P's ECOS study in 1997, no new cost studies had been undertaken until today. As a result, and given the tight schedule for the completion of the present study, some of the data required (namely, measures of coincident peak and non-coincident peak by customer class) have been taken from the load research effort undertaken for the 1997 ECOS study. All other utility cost and energy data are based on the test year 2005.[1] The framework used in this study can be used for future studies, when more detailed demand information is likely to be available.

# II. Methodology

The three key steps in an ECOS study are as follows:

(a) Functionalization, the process of assigning total cost of service to the utility functions - production, transmission, distribution, and customer, including allocation of common costs such as A&G and general plant.

(b) Classification, where the functionalized costs are classified as being demand-, energy- or customer-related, depending on what is assumed to drive the particular cost element.

(c) Allocation, where the functionalized and classified costs are assigned to the individual customer classes according to some measure of cost causation.

For purposes of this study, and to be consistent with NERA recommendations with regard to determination of revenue requirement, the plant and depreciation expense used in this study reflect original (historic) cost, as provided by BL&P.

## A. Functionalization

The first step in the ECOS study was to *functionalize* total costs into the following major categories: Generation, Transmission, Distribution and Customer. Distribution was further subdivided into the following subcategories: Distribution Substations, Distribution Primary, Line Transformers, Distribution Secondary, Meters, Services, and Customer.

BL&P's accounting system aggregates all transmission and distribution plant under a single "Distribution" category. In order to separate plant between transmission and distribution functions, the following approach was adopted:

- *Substations*: BL&P undertook an analysis of each of its distribution substations and identified the components that perform a transmission function (for instance, station transformers that convert power from 69 kV to 24 kV, switching gears located on the high side (69 kV), etc.) versus those performing a distribution function. Using the respective 2005 reproduction cost values of each of these elements, the relative shares

[1] An adjustment to the 1996 demand estimates was made in order to maintain the appropriate relationship with energy usage by class.

of substation plant functionalized as Transmission and Distribution were 50.66% and 49.34% respectively.

- *Overhead conductors and Underground cables*: NERA calculated the shares of each of these elements of plant that belong to Transmission and Distribution functions, as well as primary versus secondary lines, based on the cost breakdown by voltage level provided by the BL&P report: "Utility Fixed Assets Valuation Study"[2].

- *Poles:* The valuation study separately identified the 2005 reproduction cost associated with three types of poles, defined according to pole length (50-55 feet, 40-45 feet, 30-35 feet). BL&P advised that generally, the longest pole could be attributed to transmission, the intermediate to primary, and the shortest to secondary. Poles that support both transmission and distribution lines, were functionalized according to the higher voltage level.

Depreciation expense was functionalized in the same manner as the corresponding plant item.

The O&M expenses associated with lines and distribution substations were functionalized as transmission and distribution and the various sub-functions according to the net plant functionalization factors.

General property (which includes office buildings, furniture, computers, etc.) was assigned to each function according to labor ratios. We developed these ratios based on the respective distribution of wages and salaries to generation versus transmission and distribution. Ratios by sub-category were then computed according to the allocations of O&M expenses.

Administrative and General Expenses were functionalized according to either total plant ratios (for expenses that are clearly plant-related, such as property insurance), labor ratios (e.g., staff training), or average of plant and labor ratios (e.g. for legal expenses).

## B. Classification

### 1. Generation

Generation Plant

The main differences across ECOS studies lie in the approaches used to classify and allocate the fixed costs of generation. Since generation costs are usually the largest functional cost component, revenue allocations are particularly sensitive to the methods used for classifying and allocating generation costs. The 1997 ECOS study classified 100% of production plant as

[2] Report prepared by KEMA in January 2006.

demand-related. This approach does not recognize that while some fixed costs of production plant are incurred to provide capacity, others are incurred to provide cheaper energy than would otherwise be available. This second category of fixed costs is energy-related.

We applied a more appropriate method, the "Cap-Sub" approach, to classify the fixed costs of generation, a method widely used in the US. The "Cap-Sub" method classifies as demand-related the portion of fixed generation costs that would exist if the system consisted of all peaking units. All remaining generation costs are classified as energy-related. This approach recognizes that generation investment decisions take into account the trade-off between capacity and energy costs in order to minimize total system costs. If the only obligation of the utility were to meet peak demand, then it would install only the most inexpensive capacity. More expensive capacity is built when the associated fuel cost savings are greater than the additional fixed costs of that capacity.

We identified the 40 MW gas turbine (GT) unit as the least expensive among the types in BL&P's generation expansion plan. Using this classification approach, BL&P's generation plant is 55.8% demand-related, 44.2% energy-related. The figure below illustrates the calculations.

**Figure 1. Calculation of energy-related share of BL&P's fixed generation costs**

| | | 2005$ (000s BDS $) |
|---|---|---|
| (1) | 40-MW GT - Gas Turbine ($/MW) | $1,313 |
| (2) | System Capacity (MW) | 237.1 |
| (3) | System cost in hypothetical scenario with only GT units | $311,312 |
| (4) | 2005 RCN Gen. Gross Plant Cost | $558,029 |
| (5) | Energy-related generation plant costs | $246,717 |
| (6) | **% of energy-related Gen. Costs** | $\boxed{44.2\%}$ |

<u>Fuel costs and other Generation O&M</u>

Fuel costs were 100% classified as energy-related. We also identified the O&M generation expenses that vary directly with the volume of production, such as water for power, lubricants, other production supplies and subsurface oil recovery expenses, and classified them as energy-related. The rest of O&M expenses were classified as demand or energy-related using the proportions applied to fixed generation costs from the Cap-Sub analysis.

### 2. Transmission plant and associated expenses

Costs functionalized to transmission are typically classified as entirely demand-related, except in cases where the primary function of lines is to facilitate energy exports and/or imports, in which case they are sometimes classified as energy-related. Other methods that classify a portion of transmission costs as energy-related are also possible. Based on BL&P system characteristics, we classified all plant and O&M functionalized as transmission as 100% demand-related.

### 3. Distribution

In the case of distribution, we used the same classification employed by 1997 ECOS study: all distribution plant and expenses, except for meters and service drops, are classified as demand-related.

### 4. Customer

Meters, service drops, customer and accounting services were classified as customer-related costs. Customer accounts are composed mainly of meter-reading, accounting, billing and collection. Customer Services represents various activities such as customer assistance, informational advertising and marketing expenses.

## C. Class Allocation

The allocators used for each of the major functions are described below.

### 1. Generation

A review of BL&P's pattern of hourly system loads suggests that there is no distinct seasonal differentiation (the system is not clearly summer or winter peaking). As a result, all demand-related generation costs (plant, depreciation expense, O&M and A&G) were allocated based on the 12-Coincident Peak (12-CP) method, which allocates costs to rate classes according to the contribution of each class to the average of the 12 monthly system CPs. Our allocation factors for energy-related generation costs were based on the ratio of each class' energy sales to total energy sales (MWh). We adjusted MWh sales by energy losses to convert them in MWh measured at the generator level.[3]

[3] Loss factors were based on estimates available in the 1997 ECOS Study.

### 2. Transmission

We used 12-CP for allocation of transmission costs to customer classes. The demand 12 CP factors were available from the 1997 COS study. These factors were scaled to take into account differences in per-customer energy usage and number of customers between 1995 and 2005.

### 3. Distribution

Except for meters, services and installations on customer premises, we allocated the costs of each distribution component based on measures of non-coincident peak demand (NCP) for customers served at the various levels of distribution facility. NCP allocation methods recognize that not all distribution elements peak coincident with the system, and therefore give a greater cost responsibility to customers that peak outside the system coincident peak. There are a number of alternatives to compute NCP ratios:

- Class NCP ratios, which reflect each individual class' maximum demand compared to the sum of all the classes' maximum demands at each voltage level, irrespective of when those demands occur.

- Customer NCP ratios, which are based on the highest sum of individual customers' maximum demand within a class, compared to the sum of customers' maximum demands across all classes, for each voltage level.

We used the Class NCP method to allocate costs of distribution substations to the various customer classes. To allocate the costs of local distribution facilities (secondary lines, transformers, and primary lines) we used customer NCP ratios. This approach is consistent with the way the local distribution facilities cost is incurred (based on the maximum expected load of individual customers). In order to test the appropriateness of alternative allocation methods, we compared the embedded costs by class resulting from Customer NCP and other methods against the distribution facilities marginal costs relationships by class, using estimates of typical distribution facilities marginal costs per kVA of design demand from the 2006 NERA Marginal Cost Study.[4] The relative cost allocations which most closely approximated those obtained from marginal costs were those that relied on customer NCP factors.

Both Class and Customer NCP factors by voltage level were available from the 1997 COS study.[5] These factors were scaled to take into account differences in per-customer energy usage

[4] For this comparative analysis took we used typical distribution facilities marginal costs per kVA of design demand by class. Source: NERA report "The Barbados Light & Power Company. Marginal Cost of Electricity Service", March 2006. Draft 1. Schedule 21.

[5] However, the 1997 ECOS study used a different method to allocate the costs of primary lines; it applied the average of Class NCP and Customer NCP at primary lines.

and number of customers between 1995 and 2005. All allocation factors were grossed up to reflect the demands at the various service levels.[6]

### 4. Customer

Customer costs vary with the number and type of customers. When customers are added, BL&P faces higher costs for customer service expenses such as meter reading, collection and inspection, billing, and bad debts. New meter and service drops are also installed. The customer allocators were based on class weights for these costs as follows:

- Meter reading allocation factors were based on number of meter reads and average cost per read, by class, as provided by BL&P.
- O&M meter allocation took into account the cost of operations by type of meters used within a class.
- Allocation factors for the fixed cost of meter and services were based on the typical installed cost of each of these elements by customer type within a class;
- Collection and inspection mainly relate to domestic and general service and the allocations were based on the number of customers in these categories.
- Bad debts were allocated to domestic and secondary voltage power customers, using 65% and 35% respectively, as advised by BL&P.
- Other customer services (including billing, training, etc.) were allocated on the basis of customer numbers by class.

The specific costs associated with streetlights (such as luminaries, ballast, light bulbs and other equipment necessary for street lighting, including an allocated share of general plant) were allocated directly to the streetlight class.

### 5. Allocation of Revenue Credits

BL&P provides certain services not covered by standard rates, mainly from pole rentals. The revenues collected from these services were credited against BL&P's costs for purposes of determining revenue requirement for tariff customers. The revenues from pole rentals were assigned to each function (Transmission and Distribution), according to its respective share of this element of plant. Then transmission and distribution revenue credits were allocated to each class based on relative allocation of transmission and distribution costs by class.

[6] Demand loss factors were available from the 1997 BL&P's Embedded Cost study.

# III. Comparison of Allocated Costs with Current Tariffs

The last step of the embedded cost study compares the resulting class allocated costs to tariff revenues for test year 2005 to determine the degree of over/under recovery of allocated costs under existing tariffs.

We computed total net income as total tariff revenues for 2005 less total expenses (system expenses including O&M, A&G, depreciation, taxes). We then computed a system rate of return, as the ratio of total net income to system rate base. We applied the system average rate of return to each class' allocated rate base, to determine the required class' allocated return under a scenario with equalized rates of return by class.

Our analysis showed that in 2005, BL&P earned a rate of return of 6.54%. However, each class contributed differently towards that return. General Service, Secondary Voltage and Large Power customers contributed to revenues in excess of their allocated embedded costs, while the Domestic class, Employees and Street Lighting are contributing less than the average. This result is generally consistent with the 1997 ECOS study. The table below shows the results assuming no overall tariff increase is necessary.

| Rate Class | RORs Currently Earned By Customer Class | Tariff Changes Required to collect same ROR by class |
|---|---|---|
| **Domestic** | -1.32% | 17.48% |
| **Employees** | -5.22% | 28.62% |
| **General** | 8.42% | -3.02% |
| **S.V.P.** | 11.29% | -7.67% |
| **LP** | 15.79% | -12.51% |
| **Street Lighting** | -15.64% | 52.62% |
| **Overall** | **6.54%** | **0.00%** |

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**THE BARBADOS LIGHT & POWER COMPANY**
**RETURN AT CURRENT RATES AND REQUIRED TARIFF INCREASE BY CLASS ASSUMING NO OVERALL TARIFF INCREASE**
**Test Year 2005**
**(Based on Historic Cost for Plant and Depreciation Expense)**
**(000s BDS $)**

| | | Total System | Domestic | General | S.V.P. | LP | Street Lighting | Employees |
|---|---|---|---|---|---|---|---|---|
| (A) | **Retail Tariff Revenues (incl. Fuel Adj. Clause)** | 337,539 | 105,604 | 18,117 | 125,647 | 83,736 | 3,871 | 564 |
| (B) | **Operating Expenses** | 301,224 | 109,927 | 15,770 | 103,378 | 66,173 | 5,333 | 642 |
| | Depreciation Expense | 39,581 | 16,774 | 1,918 | 12,537 | 6,648 | 1,606 | 98 |
| | O&M Expense (incl. Fuel) | 225,072 | 79,322 | 11,915 | 78,117 | 52,082 | 3,172 | 464 |
| | A&G expense | 30,802 | 12,976 | 1,611 | 9,986 | 5,533 | 620 | 76 |
| | Taxes (Other than income) | 2,990 | 1,190 | 146 | 1,034 | 586 | 47 | 7 |
| | Income Tax | 2,779 | (335) | 180 | 1,704 | 1,344 | (112) | (2) |
| (C) | **Revenue Credits** | 2,347 | 1,220 | 112 | 655 | 329 | 25 | 7 |
| | Miscellaneous revenue | 1,692 | 963 | 79 | 429 | 200 | 16 | 6 |
| | Interest Income | 569 | 228 | 28 | 195 | 108 | 9 | 1 |
| | Exchange Gain | 86 | 29 | 4 | 31 | 21 | 1 | 0 |
| (D) | **Operating Expenses Net of Credits (B) - (C)** | 298,876 | 108,708 | 15,658 | 102,723 | 65,845 | 5,308 | 635 |
| (E) | **Net Operating Income (A)-(D)** | 38,663 | (3,103) | 2,459 | 22,924 | 17,892 | (1,436) | (72) |
| (F) | **Rate Base** | 590,860 | 234,715 | 29,210 | 203,062 | 113,319 | 9,182 | 1,372 |
| (G) | **Rate of Return (ROR) earned on Rate Base (E)/(F)** | 6.54% | -1.32% | 8.42% | 11.29% | 15.79% | -15.64% | -5.22% |
| (H) | **Equalized RORs by Class** | 6.54% | 6.54% | 6.54% | 6.54% | 6.54% | 6.54% | 6.54% |
| (I) | **Required Class Returns at Current ROR (H) x (F)** | | 15,359 | 1,911 | 13,287 | 7,415 | 601 | 90 |
| (J) | **Allocated Revenue Requirement by Class (D) + (I)** | 337,539 | 124,068 | 17,570 | 116,010 | 73,260 | 5,909 | 725 |
| (K) | **Revenue Overcollection (Undercollection) (A)-(J)** | - | (18,462) | 547 | 9,636 | 10,477 | (2,037) | (161) |
| (L) | **Required Increase (Decr) over Present Revenues (%)** | 0.0% | 17.5% | -3.0% | -7.7% | -12.5% | 52.6% | 28.6% |

# IV. Required Revenue Requirement by Class at Target Rate of Return

The table below shows the tariff increases (decreases) required for equal class rates of return if total tariff revenues are set to cover BL&P's revenue requirement, including a return on investment equal to NERA's estimate of BL&P's current weighted-average cost of capital of 10.40%.[7]

| Rate Class | Target ROR By Customer Class | Tariff Changes Required to Collect the Target ROR by Class |
|---|---|---|
| Domestic | 10.40% | 34.74% |
| Employees | 10.40% | 50.67% |
| General | 10.40% | 4.26% |
| S.V.P. | 10.40% | -1.92% |
| LP | 10.40% | -9.72% |
| Street Lighting | 10.40% | 82.36% |
| **Overall** | **10.40%** | **9.00%** |

[7] The development of this estimate is explained in detail in NERA's "Regulatory Audit of the Barbados Light & Power Co., Ltd. – Interim Report," April 2, 2006.

## THE BARBADOS LIGHT & POWER COMPANY
### REVENUE REQUIRED TO MEET TARGET RATE OF RETURN
**Test Year 2005**
**(Based on Historic Cost for Plant and Depreciation Expense)**

**(000s BDS $)**

| | Total System | Domestic | General | S.V.P. | LP | Street Lighting | Employees |
|---|---|---|---|---|---|---|---|
| (1) Rate Base | 590,860 | 234,715 | 29,210 | 203,062 | 113,319 | 9,182 | 1,372 |
| (2) Equalized Rates of Return by Class | 10.40% | 10.40% | 10.40% | 10.40% | 10.40% | 10.40% | 10.40% |
| (3) Required Return on Rate Base (1) x (2) | 61,449 | 24,410 | 3,038 | 21,118 | 11,785 | 955 | 143 |
| (4) Actual Return on Rate Base Earned | 38,663 | (3,103) | 2,459 | 22,924 | 17,892 | (1,436) | (72) |
| (5) Required Increase in Return to achieve target (3) - (4) | 22,786 | 27,514 | 579 | (1,805) | (6,106) | 2,391 | 214 |
| (6) Required Increase in Income Taxes | 7,595 | 9,171 | 193 | (602) | (2,035) | 797 | 71 |
| (7) Required Increase in Return and Income Taxes | 30,382 | 36,685 | 772 | (2,407) | (8,142) | 3,188 | 286 |
| (8) Actual System Expenses by Class in 2005 | 301,224 | 109,927 | 15,770 | 103,378 | 66,173 | 5,333 | 642 |
| (9) Total Revenue Requirement at Target Rate of Return (4)+(7)+(8) | 370,269 | 143,509 | 19,001 | 123,895 | 75,923 | 7,085 | 856 |
| (10) Less Other revenues | 2,347 | 1,220 | 112 | 655 | 329 | 25 | 7 |
| (11) Tariff Revenue Requirement by Class (9) - (10) | $367,921.19 | $142,289 | $18,889 | $123,240 | $75,594 | $7,060 | $849 |
| (12) *Required Increase over present Tariff Revenues* | 30,382 | 36,685 | 772 | (2,407) | (8,142) | 3,188 | 286 |
| (13) Required % Increase (Decr) over Present Revenues (%) | 9.0% | 34.7% | 4.3% | -1.9% | -9.7% | 82.4% | 50.7% |

**Demand-, Energy- and Customer- Related Revenue Requirement Allocation**
**at Target Rate of Return. Test Year 2005**
**(000s BDS $)**

| | TOTAL | Domestic | General | S.V.P. | LP | Street Lighting | Employees |
|---|---|---|---|---|---|---|---|
| DEMAND-RELATED | 119,557 | 51,753 | 5,661 | 41,202 | 20,155 | 467 | 319 |
| ENERGY (Non-Fuel) | 49,331 | 16,667 | 2,531 | 17,635 | 11,681 | 720 | 98 |
| FUEL | 176,669 | 58,847 | 8,813 | 63,293 | 43,361 | 2,011 | 344 |
| CUSTOMER-RELATED | 22,364 | 15,022 | 1,884 | 1,109 | 398 | 3,863 | 88 |
| TOTAL REVENUE REQUIREMENT | $367,921 | $142,289 | $18,889 | $123,240 | $75,594 | $7,060 | $849 |

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# Barbados Light & Power Company, Ltd.
# Marginal Costs of Electricity Service

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Prepared for the

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# Marginal Costs of Electricity Service

## I. Introduction

As part of an assignment for the Fair Trading Commission of Barbados (FTC), and with generous assistance from Barbados Light & Power Company, Ltd. (BL&P), NERA Economic Consulting (NERA) prepared estimates of the marginal costs of providing electricity service to consumers in Barbados. This report describes the methods used and summarizes the results of the analysis. This is the first comprehensive study of BL&P's marginal costs, and some proxy information and estimates were used in cases where detailed information was not available. Nevertheless, the marginal cost results presented here provide useful estimates to inform class revenue allocation, rate design, and other policies that require marginal cost information. Furthermore, the framework used in this study can be used for future studies, when more detailed information is likely to be available.

Why estimate marginal costs? There are several reasons. First, economic theory indicates that prices that reflect marginal costs lead to the most efficient allocation of society's scarce resources. Many economists believe that efficient resource allocation should be one of the goals of price setting in a regulated industry. Second, with growing investment by large customers in their own generating equipment and pressure to offer discounts to businesses competing with firms where electricity prices are lower, it is important for BL&P and the FTC to have accurate estimates of the marginal cost of providing service. Third, marginal cost information is essential for the design of appropriate time-differentiated rates. Finally, accurate estimates of marginal costs are essential for determining the benefits of load management, distributed generation and conservation programs, and for engineering studies such as acceptable loss levels in transformer specifications.

Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must ask and answer the question: What are *all* the additional generation, transmission and distribution costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand, and number of customers? Given the characteristics of electricity supply and demand, the cost of additional consumption may differ depending upon the time of the change in output. As a result, it is important to estimate time-differentiated marginal costs of electricity service.

NERA's approach to determining the marginal cost of electricity is to examine the system planners' and operators' response to load changes at different times of the day and year. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurement can be made.

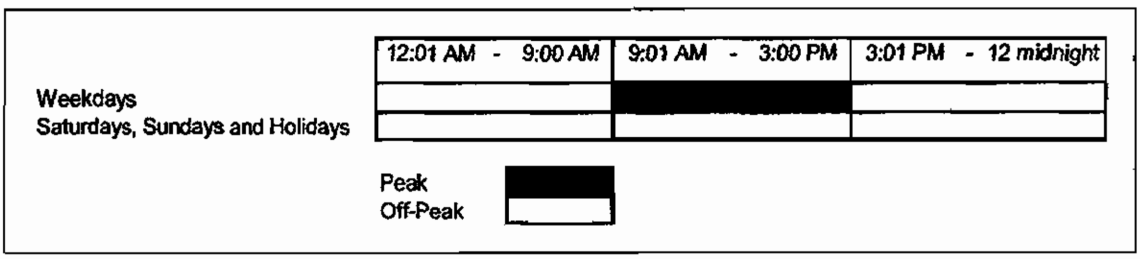
A utility's marginal costs (particularly generation costs) may not be the same every year, even in the absence of inflation. Because load forecasting is an imperfect science and capacity must often be added in discrete chunks rather than smoothly as load grows, utilities and regions often have more or less capacity than is optimal. We estimated generation costs for the period 2006 to 2010. The costs developed for this report are expressed in 2006 dollars to simplify comparisons to current rates.

## II. Selection of Costing/Pricing Periods

For purposes of providing summary tables for this report and for use in evaluation of time-differentiated rates, we developed a set of costing/pricing periods that are efficient (grouping hours of similar cost), administratively feasible, and likely to be appropriate for a significant number of years. We limited the number of periods to two seasons and two diurnal periods within each season.

Our usual process for developing recommended costing/pricing periods is to sum all the time-varying marginal costs for each hour, and use regression analysis to determine a set of periods that minimizes the squared differences between the individual hourly costs and the average for the period, while taking into consideration administrative feasibility and the need for the periods to be reasonably easy for customers to remember. In this case, because several cost elements were not detailed enough to distinguish costs at the hourly level, we selected periods using a more qualitative approach. There is little seasonality in BL&P's marginal generation costs because maintenance is performed in the months with lower loads. The patterns of hourly system loads and distribution substation loads also show little seasonality. Therefore, we have not distinguished marginal costs by season. We defined hourly periods by reviewing the available patterns of marginal energy costs, hourly transmission loads, and hourly distribution substation loads. The periods chosen are illustrated below:

**Figure 1 – Costing/Pricing Periods**



# III. Marginal Generation Costs

Marginal generation costs include the fixed costs of adding capacity to maintain adequate reliability as load grows, and marginal energy costs incurred when the marginal generating unit produces another kWh in a given hour. In years when there is sufficient capacity to meet reliability targets, a marginal kW does not trigger a capacity addition. Rather, there is a reduction in reliability (an increase in expected outage costs to customers) because load has grown but capacity has not. This "shortage cost" is the marginal generation capacity cost in such a year.

## A. Marginal Energy Costs

BL&P dispatches its generating units to minimize cost (including wear and tear on units from start-ups and cycling) and provide reliable service. The steam units are run as baseload resources, and other resources are dispatched in order of marginal running cost (lowest cost first).

BL&P provided estimates, derived from their production cost model, of the percentage of annual energy that will be produced from each unit over the period 2006-2010. Using the Company's dispatch order and annual load duration curves, we estimated the marginal running cost (fuel plus variable operating and maintenance expenses – O&M) of the unit that will be operating at the margin in each hour. We then averaged these running costs over the hours in each costing period. The results are shown in Table 1.

**Table 1 – Marginal Running Costs 2006-2010 by Period**

| | | Peak | Off-Peak |
|---|---|---|---|
| | | (2006 BBD$ per kWh) | |
| | | (1) | (2) |
| (1) | 2006 | $0.2677 | $0.1858 |
| (2) | 2007 | 0.2729 | 0.1798 |
| (3) | 2008 | 0.2569 | 0.1709 |
| (4) | 2009 | 0.1985 | 0.1635 |
| (5) | 2010 | 0.1965 | 0.1566 |

Notes:
Costing periods are defined as follows:
Peak: Monday - Friday, hours from 9:00 AM through 3:00 PM
Off-peak: All hours in Saturday, Sunday and holidays, and all remaining hours in Weekdays.

Table 2 shows the derivation of 2006 marginal energy costs in each costing period. These figures include fuel, variable O&M, expense-related overheads (administrative and general or "A&G" expenses), and revenue requirement for fuel stock and cash working capital. The development of the loader for expense-related A&G is explained in Section V.A. The adjustment for fuel stock takes into account the fact that a marginal kWh increases the size of the required fuel inventory and the carrying costs of that increment of fuel inventory is a component of marginal energy cost. Cash working capital is required to bridge the gap between the time BL&P pays for fuel and O&M and the time the utility is reimbursed by its customers. The marginal energy costs are adjusted for losses, which are a function of load flows in a given hour. The development of the loss factors is described in Section V.B.

**Table 2 – Derivation of Marginal Energy Costs by Period - 2006**

| | | 2006 Peak Hours (2006 BBD$ per kWh) | 2006 Off-Peak Hours (2006 BBD$ per kWh) |
|---|---|---|---|
| (1) | Marginal Running Cost Including Variable O&M Expense | 0.2677 | 0.1858 |
| (2) | Variable O&M Expense Included in Marginal Running Costs | 0.0123 | 0.0185 |
| (3) | Marginal Running Cost less Variable O&M Expense | 0.2555 | 0.1673 |
| (4) | A&G Loading for Variable O&M (2) x 24.562% | 0.0030 | 0.0046 |
| (5) | *Cash Working Capital* | | |
| | Non-Fuel [(2) + (4)] x 12.500% | 0.0019 | 0.0029 |
| | Fuel (3) x 12.500% | 0.0319 | 0.0209 |
| | Fuel Stock (3) x 3.130% | 0.0080 | 0.0052 |
| | | 0.0418 | 0.0290 |
| (6) | Revenue Requirements (5) x 6.000% | 0.0025 | 0.0017 |
| (7) | Marginal Energy Cost (1)+(4)+(6) | 0.2733 | 0.1921 |
| | Marginal Energy Loss Factors For Supply at: | | |
| (8) | Primary Voltage | 1.0781 | 1.0607 |
| (9) | Secondary | 1.1101 | 1.0853 |
| | Marginal Energy Costs Including Losses: | | |
| (10) | Primary Voltage | 0.2946 | 0.2038 |
| (11) | Secondary | 0.3033 | 0.2085 |

The results by costing period for the entire study period (2006-2010) are shown on Table 3.

**Table 3 – 2006-2010 Marginal Energy Costs by Period**

| | | Peak | Off-Peak |
|---|---|---|---|
| | | (2006 BBD$ per kWh) | |
| | | (1) | (2) |
| Primary | | | |
| (1) | 2006 | $0.2946 | $0.2038 |
| (2) | 2007 | 0.3002 | 0.1973 |
| (3) | 2008 | 0.2828 | 0.1878 |
| (4) | 2009 | 0.2193 | 0.1799 |
| (5) | 2010 | 0.2171 | 0.1725 |
| Secondary | | | |
| (6) | 2006 | $0.3033 | $0.2085 |
| (7) | 2007 | 0.3091 | 0.2065 |
| (8) | 2008 | 0.2912 | 0.1966 |
| (9) | 2009 | 0.2258 | 0.1883 |
| (10) | 2010 | 0.2236 | 0.1805 |

## B. Marginal Generation Capacity Costs

If load grows in hours when capacity is tight, there is a reduction in reliability, which is a marginal shortage cost imposed on consumers. When the shortage cost is sufficiently high, it is cost-effective to add capacity to restore reliability to the acceptable level. In years when an increment of load would not trigger a capacity addition, there is still a marginal capacity cost – the cost to consumers of the reduced reliability that results when load grows but capacity remains the same.

The type of capacity added solely to restore reserves to the required level in response to load growth is generally a peaking unit, such as a combustion turbine. Generating units designed to run more often than peakers have higher fixed costs, which are only justified when their variable costs are low enough to warrant their dispatch in many hours, not just in peak hours. The fixed costs of baseload or intermediate units are thus incurred for both capacity and energy reasons.

BL&P's current near-term base case expansion plan includes the addition of a 30-MW low-speed diesel unit. We have used the cost of the low-speed diesel unit as the starting point for marginal generation capacity cost estimates.

Table 4 shows the development of the annualized cost of the low-speed diesel unit. The investment cost per kW (including land, infrastructure, and substation costs associated with the new unit) is adjusted for an estimate of marginal general property, and annualized using an economic carrying charge that includes an allowance for plant-related A&G. Fixed O&M, including non-plant-related A&G, and an allowance for working capital are added. The working capital factor includes cash, materials, spares and prepayments. Each of the major factors used to convert the investment cost of the unit to an annual value is discussed later in this report.

The last line on Table 4 divides the annual cost by one minus the effective forced outage rate (EFOR) of the low-speed diesel unit. This adjustment recognizes that the unit will not always be available to provide an additional kW of capacity when needed, and grosses up the investment to represent a "perfect" kW that is available in all hours when it can be economically dispatched.

**Table 4 – Annual Cost of Low-Speed Diesel Unit**

| | | (2006 BBD$ per kW) |
|---|---|---|
| (1) | Installed Cost of Low-Speed Diesel | $2,275.95 |
| (2) | Substation | $179.00 |
| (3) | Infrastructure Development | $75.00 |
| (4) | Total Investment | $2,529.95 |
| (5) | With General Property Loading (4) x 1.0933 | $2,766.07 |
| (6) | Annual Economic Charge Related to Capital Investment | 4.60% |
| (7) | A&G Loading | 1.01% |
| (8) | Total Annual Carrying Charge (6)+(7) | 5.61% |
| (9) | Annualized Costs (4) x (8) | $155.25 |
| (10) | Fixed O&M Expenses per kW | $64.00 |
| (11) | With A&G Loading (10) x 1.2456 | $79.72 |
| (12) | Subtotal (9)+(11) | $234.97 |
| | Working Capital | |
| (13) | Material and Spares (2) x 1.70% | $2.64 |
| (14) | Prepayments (9) x 0.43% | $0.67 |
| (15) | Cash Working Capital Allowance (11) x 12.50% | $9.96 |
| (16) | Total Working Capital (13)+(14)+(15) | $13.27 |
| (17) | Revenue Requirement for Working Capital (16) x 6.00% | $0.80 |
| (18) | Annual Fixed Costs (12)+(17) | $235.76 |
| (19) | Adjustment for Effective Forced Outage Rate (18) / 0.965 | $244.31 |

To yield a pure capacity cost, the annual costs per kW shown on Table 4 must be reduced by the expected fuel savings provided by a marginal kW of new low-speed diesel capacity. These fuel savings are computed by multiplying the unit's expected energy production per kW by the difference between the unit's running cost (fuel plus variable O&M) and the average system marginal running cost in the unit's first full year of operation. This crediting of annual fixed costs of the marginal kW for fuel savings recognizes that the last kW is required to meet marginal load only in a single (or very few) hours of the year. If the unit runs in other hours, that is because it displaces a resource with higher running costs.

**Table 5 – Net Annual Marginal Cost of Generation Capacity**

| | | |
|---|---|---|
| (1) | Dual Fuel LSD Running Cost (2006 BBD$ per kWh) | $0.1357 |
| (2) | Average Marginal Running Cost in 2009 - First full year of operation (2006 BBD$ per kWh) | $0.1698 |
| (3) | Savings per kWh Run (2)-(1) (2006 BBD$) | $0.0341 |
| (4) | Inflation Adjustment for Fuel | 1.0612 |
| (5) | 2009 Net Generation (MWh) | 182,783 |
| (6) | Gross Capacity of LSD (MW) | 30 |
| (7) | Annual Fuel Savings in 2009 (2006 *$ per kW) (3)*(4)*(5)/(6)* | $220.16 |
| (8) | Annual Fixed Costs per kW | $244.31 |
| (9) | Annual Fixed Costs Net of Fuel Savings (2006BBD$ per kW) (8)-(7) | $24.16 |
| | Note: *Inflation Adjustment reflects real fuel price* escalation between 2006 and 2009. | |

Table 5 shows annual marginal generation capacity costs for a year in which an increment of peak load would trigger a capacity addition. In any particular year, marginal load growth will not necessarily trigger a capacity addition. However, it will reduce the reliability of service for customers over all. The marginal cost of generation capacity can be computed for a particular year by adjusting the net annual cost of the next capacity addition by the ratio of expected loss-of-load hours (LOLH) in that year to target LOLH, as shown on Table 6. This ratio, which is less than one when there is excess capacity on the system (and more than one when the system has below target reliability), reflects the reduced (increased) capacity cost in those years.[1]

[1] The rationale for this adjustment is described in more detail in Appendix A.

**Table 6 – Annual Marginal Generation Capacity Costs, 2006-2010**

| | Annual Net Cost of Generation Capacity (2006 BBD$ per kW) (1) | Forecast LOLP (2) | Target LOLP (3) | Ratio of Forecast to Target LOLP (4) (2)/(3) | Marginal Generation Capacity Cost (2006 BBD$ per kW) (5) (1) x (4) |
|---|---|---|---|---|---|
| 2006 | $24.16 | 0.164% | 0.274% | 0.60 | $14.47 |
| 2007 | $24.16 | 0.299% | 0.274% | 1.09 | $26.37 |
| 2008 | $24.16 | 0.056% | 0.274% | 0.20 | $4.89 |
| 2009 | $24.16 | 0.143% | 0.274% | 0.52 | $12.63 |
| 2010 | $24.16 | 0.239% | 0.274% | 0.87 | $21.04 |

The annual costs must then be time-differentiated. BL&P's system expansion model provides estimates of annual loss-of-load hours (LOLH), but does not provide LOLH by month or hour. Because BL&P schedules maintenance on its generators in months when loads are relatively low, we assumed that LOLH is uniform across the months of the year. Within a month, capacity costs were assigned to hours when the system's combustion turbines (peaking units) are expected to operate. Identification of these hours is an approximation of an assessment of various hours' relative probability of peak. Table 7 shows the resulting generation capacity cost time-differentiation factors, summarized by costing period.

**Table 7 – Time-Differentiation Factors for Generation Capacity Costs**

| | *Hours when* peaker is at margin | *Percent* of Total | *Used* in Study |
|---|---|---|---|
| Peak | 104 | 99% | 100% |
| Off-Peak | 1 | 1% | 0% |
| Total | 105 | 100% | 100% |

Table 8 shows the monthly marginal generation capacity costs per kW at each voltage level of service, by costing period. The annual costs, adjusted for peak demand losses, are assigned to costing periods using the factors in Table 7 and divided by the number of months to produce monthly costs per kW.

**Table 8 – Monthly Generation Capacity Cost per kW by Voltage Level**

| | | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| | | ---------2006 BBD$ per peak period kW per month--------- | | | | |
| (1) | Monthly Marginal Generation Capacity Cost | $1.21 | $2.20 | $0.41 | $1.05 | $1.75 |
| | Adjusted for Losses: | | | | | |
| (2) | Primary Service | $1.30 | $2.37 | $0.44 | $1.13 | $1.89 |
| (3) | Secondary Service | $1.32 | $2.41 | $0.45 | $1.15 | $1.92 |

# IV. Marginal Transmission Costs

For most utilities, the long-term marginal cost of transmission can be estimated from the typical investment per kW of transmission added to meet load growth. Transmission investment is somewhat lumpy, so the addition of capacity in a given year does not necessarily reflect load growth in that year. We normally rely on the cost of budgeted growth-related transmission projects over the budget period as the basis for our marginal cost estimates.

Projects considered to be growth-related include those driven by load growth and those necessary to upgrade existing facilities to maintain the target level of reliability. Transmission expenditures that replace existing facilities without adding capacity would be undertaken even in the absence of load growth and, therefore, are not marginal. Projects that connect generation to the network are generation-related and not functionally transmission. Projects that bring the system to a new target level of reliability (such as BL&P's undergrounding of existing transmission lines) are also not marginal.

BL&P provided its capital budget for the period 2006-2010 and identified the growth-related expenditures. The single transmission substation project in the budget is designed to accommodate near-term load growth. However, the growth-related transmission lines are designed to handle 20 years of load growth. Table 9 shows the size of these two categories of investment, the load growth driving them, and the total investment per kW of load growth.

**Table 9 – Marginal Transmission Investment**

| | | |
|---|---|---|
| (1) | Investment in Growth-Related Additions to Transmission Substations, 2006-2010 (Thousands of 2006 BBD$) | $540 |
| (2) | Estimated Additions to Transmission Substation Peak Load, 2006-2010 (MW) | 33.7 |
| (3) | Marginal Investment in Growth-Related Transmission Substations per Kilowatt (2006 BBD$) (1) / (2) | $16.02 |
| (4) | Investment in Growth-Related Additions to Transmission Lines, 2006-2010 (Thousands of 2006 BBD$) | $37,127 |
| (5) | Estimated Additions to Transmission Peak Load, 2006-2026 (MW) | 187.0 |
| (6) | Marginal Investment in Growth-Related Transmission Substations per Kilowatt (2006 BBD$) (4) / (5) | $198.52 |
| (7) | Total Marginal Transmission Investment per kW (3) + (6) | $214.54 |

When load growth requires transmission investment, marginal transmission O&M expenses are also incurred. BL&P does not separately record transmission and distribution O&M costs, and the same crews work on both systems. As a result, it was not possible to estimate a separate marginal O&M expense for transmission. All transmission and distribution O&M expenses were treated as distribution O&M, as described below.

Table 10 shows the development of annualized marginal transmission cost, which follows the same procedure used for the annualized low-speed diesel cost on Table 4 above.

**Table 10 – Annual Marginal Transmission Cost**

| | | Substations | Lines |
|---|---|---|---|
| | | -----2006 BBD$ per kW----- | |
| (1) | Marginal Investment per kW | $16.02 | $198.52 |
| (2) | With General Property Loading (1) x 1.0933 | 17.52 | 217.05 |
| (3) | Annual Economic Carrying Charge Related to Capital Investment | 5.39% | 5.58% |
| (4) | A&G Loading (plant related) | 0.59% | 2.31% |
| (5) | Total Annual Carrying Charge (3) + (4) | 5.98% | 7.89% |
| (6) | Annualized Costs (2) x (5) | 1.05 | 17.13 |
| (7) | O&M Expenses | NA | NA |
| (8) | With A&G Loading (7) x 1.2456 (Non-plant Related) | 0.00 | 0.00 |
| (9) | Subtotal (6) + (8) | 1.05 | 17.13 |
| | Working Capital | | |
| (10) | Material and Spares (2) x 1.70% | 0.30 | 3.69 |
| (11) | Prepayments (2) x 0.43% | 0.08 | 0.93 |
| (12) | Cash Working Capital Allowance (8) x 12.50% | 0.00 | 0.00 |
| (13) | Total Working Capital (10) + (11) + (12) | 0.37 | 4.62 |
| (14) | Revenue Requirement for Working Capital (13) x 6.00% | 0.02 | 0.28 |
| (15) | Total Annual Transmission Costs (9) + (14) | 1.07 | 17.40 |

Transmission capacity is sized to handle annual peak demands on the transmission system. We typically use the estimated relative probability of annual transmission system peak, based on five years of historical hourly transmission loads, to time-differentiate transmission marginal costs. In this case, data problems made that approach difficult to implement. As a proxy, we identified the hours in which load is within about five percent of annual peak load, and assigned the transmission costs equally to those hours. We then simplified the time-differentiation by rolling the small amount of cost responsibility in the off-peak hours to the peak period.

Table 11 shows the time-differentiation factors for marginal transmission costs.

**Table 11 – Time-Differentiation Factors for Marginal Transmission Costs**

| | | Hours Within 5% of peak | Percent of Total | Factor Used in Study |
|---|---|---|---|---|
| (1) | Peak | 441 | 96% | 100% |
| (2) | Off-Peak | 19 | 4% | 0% |
| (3) | Total | 460 | 100% | 100% |

Table 12 shows the monthly time-differentiated marginal transmission costs, using the annual costs developed on Table 10 (after adjustment for demand losses) and the time-differentiation factors for marginal transmission costs. The annual costs have been divided by number of months to convert to monthly costs.

**Table 12 – Monthly Marginal Transmission Costs**

| | | Peak | Off-Peak |
|---|---|---|---|
| | | (2006 BBD$ per kW-month) | |
| | | (1) | (2) |
| (1) | Monthly Marginal Transmission Cost | $1.54 | $0.00 |
| | Adjusted for Losses | | |
| (2) | Primary | $1.66 | $0.00 |
| (3) | Secondary | $1.69 | $0.00 |

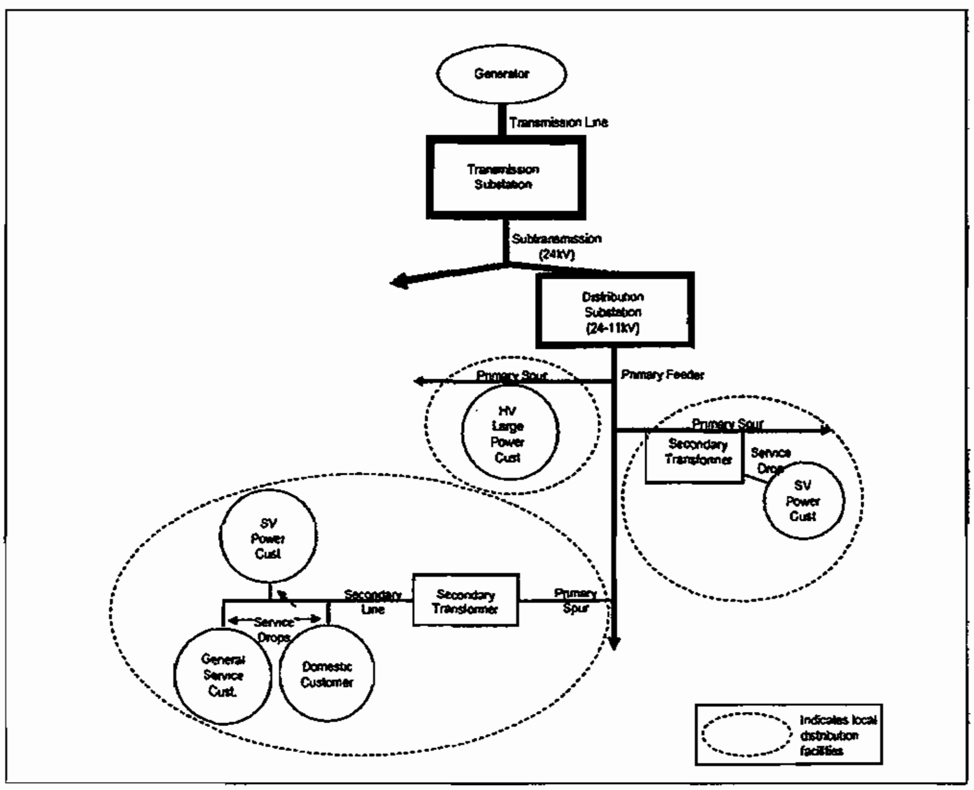
# V. Distribution Marginal Costs

## A. Marginal Distribution Investment

Conceptually, most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Marginal cost studies have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. This has led to semantics arguments about the definition of the customer-related and demand-related components. In fact, for most distribution systems, this two-part segmentation of distribution equipment is not consistent with the cost drivers.

The diagram below illustrates BL&P's distribution system and the various configurations of typical customer connections.

**Figure 2 – Simplified Diagram of BL&P's Distribution System**



The service drop is clearly customer-specific, but depends upon the customer's *maximum expected load*. We refer to secondary lines, transformers and the small amount of primary line (the primary "spur") that links the transformer to the main primary line as local distribution facilities (shown in dashed ovals in the figure). These are designed using engineering design standards that take into consideration the number of customers and the *maximum expected* loads of customers who will eventually use those facilities, over the life of the facilities. The cost per kVA of local distribution facilities can vary with type of service (overhead or underground), customer density, and customer size (due to economies of scale). The distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected long-term peak load of customer.

Because the marginal cost of local distribution facilities is incurred based on the maximum expected load of customers, and does not vary with a customer's actual peak load from month to month, or (barring major expansion) from year to year, it makes sense to recover these marginal distribution costs in a fixed monthly charge imposed on the customer's maximum expected load (or a proxy such as transformer size, contract capacity, or actual peak in the past year or two).

BL&P generally adds distribution substation capacity and distribution feeders as peak load in the areas served by these facilities grows. Thus, these costs are appropriately recovered in monthly usage charges based on peak demands or per-period energy use.

### 1. Local Distribution Facilities

BL&P identified the installed cost per kVA of design demand for a sample of customer configurations,[2] and provided weights for converting the sample information into a typical investment for each customer class. The installed costs per kVA of design demand by class are shown on Table 13. We assumed that the distribution facilities costs for street lights are the same as those for domestic customers.

[2] Excluding costs recovered through upfront payments by customers.

**Table 13 – Local Distribution Facilities Investment per kVA by Class**

| | Customer Class | Average Investment per kVa of Design Demand (2006 BBD$) |
|---|---|---|
| | | (1) |
| (1) | Domestic | $704.46 |
| (2) | General Service | $704.46 |
| (3) | Secondary | $255.45 |
| (4) | Large Power | $53.09 |

BL&P also provided estimates of the current installed costs of the predominant service drops, meters and related equipment[3] by rate schedule. Those costs are shown in Table 14.

**Table 14 – Typical Meter and Service Drop Investment by Class**

| | Customer Class | Meter Investment | Service Investment |
|---|---|---|---|
| | | (2006 BBD$ per Customer) | |
| | | (1) | (2) |
| (1) | Domestic | $98.14 | $223.05 |
| (2) | General Service | 98.14 | 92.89 |
| (3) | Secondary (self-contained) | 497.36 | 456.21 |
| (4) | Large Power (11kV Polemount) | 13,953.14 | 0.00 |

## 2. Distribution Substations and Feeders

As outlined above, distribution substation capacity and feeders are added based upon year-to-year changes in local peak loads, not based on design demands. Therefore, the marginal costs of these investments are most appropriately expressed in terms of kilowatts of load growth, and time-differentiated to indicate in which periods load growth is most likely to trigger capacity additions.

[3] Potential transformers and current transformers are a required part of the metering equipment for higher voltage customers.

BL&P's marginal (growth-related) investment in distribution substations and feeders was estimated by dividing the budgeted growth-related investment for each (expressed in 2006 dollars) in 2006-2010 by the estimated non-coincident peak load growth on the distribution substations for the same years.[4] This gives an estimate of the typical investment per kilowatt of load growth at the substation level. The calculations are shown in Table 15.

**Table 15 – Marginal Distribution Substation and Feeder Investment**

| | | |
|---|---|---|
| (1) | Investment in Growth-Related Additions to Distribution Substation Plant, 2006-2010 (Thousands of 2006 BBD$) | $9,712 |
| (2) | Estimated Additions to Distribution Substation Non-coincident Peak Load, 2006-2010 (MW) | 47.18 |
| (3) | Marginal Investment in Growth-Related Distribution Substations per Non-Coincident Kilowatt (2006BBD$) (1) / (2) | $205.86 |
| (4) | Investment in Growth-Related Additions to Distribution Feeders, 2006-2010 (Thousands of 2006 BBD$) | $8,098 |
| (5) | Marginal Investment in Growth-Related Distribution Feeders per Non-Coincident Kilowatt (2006BBD$) (4) / (2) | $171.64 |

Distribution substation and feeder annual costs were assigned to the peak period only. A review of hourly loads on three sample distribution substations contributed to the definition of the peak period.

## B. Distribution Operation and Maintenance Expenses

Each type of distribution plant requires O&M, so marginal O&M expenses are incurred when load growth triggers capacity additions. We began with an analysis of BL&P's average level of

[4] We estimated growth in non-coincident substation peaks by assuming that the same relationship between forecast coincident peak and non-coincident peak for three sample substations applies to all substations.

transmission plus distribution O&M expenses[5] in 2001-2005 as a guide for estimating marginal O&M costs.

Substation expenses include the substation account plus SCADA expenses. Local distribution facilities expenses include maintenance of mains, trouble calls, maintenance of transformers, and damage to customer premises. Meter O&M is identified separately and there is an explicit account for maintenance of street lighting. The other categories (superintendence, training and maintenance of plant records) were allocated proportionally to the substation, distribution facilities, meter and street lighting categories.

O&M expenses by category for each year were converted into 2006 dollars using a weighted labor and material cost index. The substation expenses were then divided by kilowatts of estimated substation non-coincident peak load. The distribution facilities expenses were also divided by non-coincident substation peak load, but then converted to expense per kW of design demand. The meter O&M expenses were divided by weighted number of customers using weights provided by BL&P that reflect the relative costs associated with meters used by each class. The street lighting expenses were divided by number of fixtures. These calculations provide a historical pattern of the per-unit O&M expenses. For each category of O&M we used an average of the years considered most representative of future marginal expenses.

Table 16 shows the development of the meter O&M expense per weighted customer. Table 17 takes that value and multiplies by the appropriate weight for each class to yield a meter O&M expense per customer.

[5] As mentioned above, BL&P does not keep separate records of transmission and distribution O&M, and so all of these expenses were treated as distribution O&M.

## Table 16 – Meter O&M per Weighted Customer

| | Year | Total Meter Operation & Maintenance Expenses | Average Number of Customers | Weighted Average Number of Customers | Meter Expense Per Weighted Customer | Weighted Labor and Materials Cost Index | Meter Expense Per Weighted Customer |
|---|---|---|---|---|---|---|---|
| | | ( BBD$) | | | (BBD$) | (2006 = 1.00) | (2006 BBD$) |
| | | | | (2) x 1.70 | (1)/(3) | | (4)/(5) |
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| (1) | 2001 | $702,702 | 105,195 | 178,832 | $3.93 | 0.85 | $4.65 |
| (2) | 2002 | 715,671 | 107,232 | 182,294 | 3.93 | 0.87 | 4.51 |
| (3) | 2003 | 824,918 | 109,488 | 186,130 | 4.43 | 0.90 | 4.94 |
| (4) | 2004 | 984,394 | 111,743 | 189,963 | 5.18 | 0.92 | 5.64 |
| (5) | 2005 | 663,885 | 113,720 | 193,324 | 3.43 | 0.96 | 3.59 |
| (6) | Estimated Annual Marginal Meter O&M Expense per Weighted Customer (Average 2001-2005) | | | | | | $4.67 |

## Table 17 – Meter O&M per Customer

| | Class | Weighting Factor | Annual Meter Expense Per Customer |
|---|---|---|---|
| | | | (2006 BBD$) |
| | | | (1) x $4.67 |
| | | (1) | (2) |
| (1) | Domestic | 1.00 | $4.67 |
| (2) | General Service | 6.27 | 29.28 |
| (3) | Secondary | 2.19 | 10.23 |
| (4) | Large Power | 58.30 | 272.11 |

Table 18 shows the development of the distribution facilities O&M. Because customers use different elements of the distribution system, the O&M expense estimates for distribution facilities were separated into primary and secondary. We estimated primary and secondary expenses based on the share of transformer expenses in the total, and the ratio of primary to secondary line miles.

## Table 18 – Distribution Facilities O&M per kVA of Design Demand

| | Year | Transformer Expenses (BBD$) | Other Distribution Facilities Expenses (BBD$) | Estimated Design Demands | | Transformer Expenses per kVa of Secondary Design Demand | Other Distribution Facilities Expenses Per kVa of Design Demand (BBD$) | | Weighted Labor & Materials Cost Index (2006=1.00) | Transformer Expenses per kVa of Design Demand (2006 BBD$) | Other Distribution Facilities Expenses Per kVa of Design Demand (2006 BBD$) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Primary (kVa) | Secondary (kVa) | | Primary | Secondary | | | Primary | Secondary |
| | | | | | | | (2)*.33 / ((3)+(4)) | (2)*.67 / (4) | | (5)/(8) | (6)/(8) | (7)/(8) |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
| (1) | 2001 | 330,683 | 5,475,267 | 260,775 | 538,587 | 0.61 | 2.23 | 6.86 | 0.85 | 0.73 | 2.63 | 8.11 |
| (2) | 2002 | 336,786 | 5,461,756 | 260,775 | 556,170 | 0.61 | 2.17 | 6.63 | 0 87 | 0.70 | 2.50 | 7.61 |
| (3) | 2003 | 388,197 | 5,721,007 | 259,350 | 571,860 | 0.68 | 2.24 | 6.75 | 0.90 | 0.76 | 2.50 | 7.53 |
| (4) | 2004 | 463,244 | 5,796,285 | 259,350 | 584,309 | 0.79 | 2.23 | 6.69 | 0.92 | 0.86 | 2.43 | 7.29 |
| (5) | 2005 | 312,417 | 6,152,585 | 255,075 | 603,308 | 0.52 | 2.33 | 6 88 | 0.96 | 0.54 | 2.44 | 7.20 |
| (6) | *Used in Study (average of 2001-2005)* | | | | | | | | | *0.72* | *2.50* | *7.55* |
| (7) | | Estimated Distribution Facilities O&M for a Primary Customer<br>Col. (10) Line (6) (BBD$ per kVA per year) | | | | | | $ 2.50 | | | | |
| (8) | | Estimated Distribution Facilities O&M for a Secondary Customer<br>Sum of Line (6) (BBD$ per kVA per year) | | | | | | $ 10.77 | | | | |

Table 19 shows the development of the distribution substation O&M.

**Table 19 – Distribution Substation O&M per kW of Peak Demand**

| | Year | Total Distribution Substation Expenses | Estimated Substation Noncoincident Peak Loads | Substation Expenses Per kW of Substation Noncoincident Peak Loads | Weighted Labor and Materials Cost Index | Substation Expenses Per kW of Substation Noncoincident Peak Loads |
|---|---|---|---|---|---|---|
| | | (BBD$) | (kW) | (BBD$) | (2006=1.00) | (2006 BBD$) |
| | | | | (1) / (2) | | (3) / (4) |
| | | (1) | (2) | (3) | (4) | (5) |
| (1) | 2001 | $2,014,755 | 182,560 | 11.04 | 0.85 | $13.05 |
| (2) | 2002 | 2,112,091 | 188,580 | 11.20 | 0.87 | 12.87 |
| (3) | 2003 | 2,123,030 | 198,240 | 10.71 | 0.90 | 11.95 |
| (4) | 2004 | 2,154,061 | 200,200 | 10.76 | 0.92 | 11.72 |
| (5) | 2005 | 2,797,684 | 215,880 | 12.96 | 0.96 | 13.55 |
| (6) | Used in Study (average of 2001-2005) | | | | | $12.63 |

Table 20 shows the development of street light O&M expenses.

**Table 20 – Annual Street Light O&M Expenses**

| | Year | Total Street Light Operation & Maintenance Expenses | Number of Lamps | Street Light Expense Per Lamp | Weighted Labor and Materials Cost Index | Street Light Expense Per Lamp |
|---|---|---|---|---|---|---|
| | | ( BBD$) | | (BBD$) | (2006 = 1.00) | (2006 BBD$) |
| | | | | (1)/(2) | | (4)/(5) |
| | | (1) | (2) | (3) | (4) | (5) |
| (1) | 2005 | $619,965 | 25,590 | $24.23 | 0.96 | $25.34 |
| (2) | Estimated Annual Marginal Street Light O&M Expense per Lamp | | | | | $25.34 |

Tables 21-23 show the derivation of the annualized costs of meters and services, local distribution facilities, and distribution substations and feeders, respectively. The customer service expenses included on Table 21 are discussed in the next section. Table 24 applies demand losses and time-differentiates the distribution substation and feeder costs.

### Table 21 – Annualized Marginal Meter, Service and Customer Service Costs

| | | Domestic | General Service | Secondary | Large Power |
|---|---|---|---|---|---|
| | | | -------- (2006 BBD$ per Customer) ------- | | |
| Investment - Meter & Services | | (1) | (2) | (3) | (4) |
| (1) | Meter Investment per Customer | $98.14 | $98.14 | $497.36 | $13,953.14 |
| (2) | With General Property Loading (1) x 1.0933 | 107.30 | 107.30 | 543.78 | 15,255.35 |
| (3) | Annual Economic Charge Related to Capital Investment | 6.08% | 6.08% | 6.08% | 6.08% |
| (4) | Service Investment per Customer | $223.05 | $92.89 | $456.21 | $0 00 |
| (5) | With General Property Loading (1) x 1.0933 | 243.87 | 101.55 | 498.79 | 0.00 |
| (6) | Annual Economic Charge Related to Capital Investment | 7 61% | 7.61% | 7.61% | 7.61% |
| (7) | A&G Loading (Plant Related) | 0.59% | 0.59% | 0.59% | 0.59% |
| (8) | Total Carrying Charge Meters (3) + (7) | 6.67% | 6.67% | 6.67% | 6.67% |
| (9) | Total Carrying Charge Services (6) + (7) | 8.20% | 8.20% | 8.20% | 8.20% |
| (10) | Annualized Meter Costs (2) x (8) | 7.16 | 7.16 | 36.28 | 1,017.84 |
| (11) | Annualized Service Costs (5) x (9) | 19.99 | 8.32 | 40 88 | 0.00 |
| (12) | Annualized Meter & Service Costs (10)+(11) | 27.15 | 15.48 | 77.16 | 1,017.84 |
| O&M - Meter, Customer Service Expenses | | | | | |
| (13) | Meter O&M Expenses | 4 67 | 29.28 | 10 23 | 272.11 |
| (14) | Customer Service Expenses | 66.99 | 66.22 | 62.98 | 45.90 |
| (15) | With A&G Loading [(13)+(14)] x 1.2456 (Non-plant Related) | 89.26 | 118.96 | 91.19 | 396.12 |
| (16) | Customer-Related Costs (12) + (15) | 116.41 | 134.44 | 168.35 | 1,413.96 |
| | Working Capital | | | | |
| (17) | Materials and Spares [(2) + (5)] x 1.70% | 5.97 | 3.55 | 17.72 | 259.34 |
| (18) | Prepayments [(2) + (5)] x 0.430% | 1.51 | 0 90 | 4.48 | 65.60 |
| (19) | Cash Working Capital (15) x 12.50% | 11.16 | 14.87 | 11.40 | 49.52 |
| (20) | Revenue Requirement for Working Capital [(17)+(18)+(19)] x 6.00% | 1.12 | 1.16 | 2.02 | 22.47 |
| (21) | Total Annual Marginal Customer-Related Costs (16) + (20) | $117.53 | $135.60 | $170.37 | $1,436 43 |

## Table 22 – Annualized Local Distribution Facilities Costs per kVA of Design Demand

| | | Domestic | General Service | Secondary | Primary |
|---|---|---|---|---|---|
| | | ------ (2006 BBD$ per kVA) ---------- | | | |
| | | (1) | (2) | (3) | (4) |
| (1) | Marginal Investment per kVA | $704.46 | $704.46 | $255.45 | $53.09 |
| (2) | With General Property Loading (1) x 1.0933 | 770.21 | 770.21 | 279.29 | 58.04 |
| (3) | Annual Economic Carrying Charge Related to Capital Investment | 6.39% | 6.39% | 6.39% | 6.39% |
| (4) | A&G Loading (plant-related) | 2.36% | 2.36% | 2.36% | 2.36% |
| (5) | Total Annual Carrying Charge (3) + (4) | 8.74% | 8.74% | 8.74% | 8.74% |
| (6) | Annualized Costs (2) x (5) | 67.35 | 67.35 | 24.42 | 5.07 |
| (7) | O&M Expense per kVA | 10.77 | 10.77 | 10.77 | 2.50 |
| (8) | With A&G Loading (7) x 1.2456 (non-plant related) | 13.41 | 13.41 | 13.41 | 3 11 |
| (9) | Subtotal (6) + (8) | 80.75 | 80.75 | 37.83 | 8.19 |
| | Working Capital | | | | |
| (10) | Material and Spares (2) x 1.70% | 13.09 | 13.09 | 4.75 | 0.99 |
| (11) | Prepayments (2) x 0.43% | 3.31 | 3.31 | 1.20 | 0.25 |
| (12) | Cash Working Capital Allowance (8) x 12.50% | 1.68 | 1.68 | 1.68 | 0.39 |
| (13) | Total Working Capital (10) + (11) + (12) | 18.08 | 18.08 | 7.63 | 1.63 |
| (14) | Revenue Requirement for Working Capital (13) x 6.00% | 1.08 | 1.08 | 0.46 | 0.10 |
| (15) | Total Annual Marginal Distribution Facilities Costs (9) + (14) | 81.84 | 81.84 | 38.29 | 8.29 |

## Table 23 – Annualized Distribution Substation and Feeder Costs

| | | Substations | Feeders |
|---|---|---|---|
| | | 2006 BBD$ per kW | |
| (1) | Marginal Investment per kW | $205.86 | 171.64 |
| (2) | With General Property Loading (1) x 1.0933 | 225.07 | 187.66 |
| (3) | Annual Economic Carrying Charge Related to Capital Investment | 5.39% | 6.39% |
| (4) | A&G Loading (plant related) | 0.59% | 2.36% |
| (5) | Total Annual Carrying Charge (3) + (4) | 5.98% | 8.74% |
| (6) | Annualized Costs (2) x (5) | 13.46 | 16.41 |
| (7) | O&M Expenses | 12.63 | |
| (8) | With A&G Loading (7) x 1.2456 (Non-plant Related) | 15.73 | |
| (9) | Subtotal (6) + (8) | 45.59 | |
| | Working Capital | | |
| (10) | Material and Spares (2) x 1.70% | 7.02 | |
| (11) | Prepayments (2) x 0.43% | 1.77 | |
| (12) | Cash Working Capital Allowance (8) x 12.50% | 1.97 | |
| (13) | Total Working Capital (10) + (11) + (12) | 10.76 | |
| (14) | Revenue Requirement for Working Capital (13) x 6.00% | 0.65 | |
| (15) | Total Distribution Substation Costs (9) + (14) | 46.24 | |

## Table 24 – Monthly Distribution Substation and Feeder Costs

| | | Peak | Off-Peak |
|---|---|---|---|
| | | (2006 BBD$ per kW-month) | |
| | | (1) | (2) |
| (1) | Monthly Marginal Distribution Substation and Feeder Cost | $3.85 | $0.00 |
| | Adjusted for Losses: | | |
| (2) | Primary | $4.03 | $0.00 |
| (3) | Secondary | $4.10 | $0.00 |

Table 25 shows the development of annual costs of street light fixtures.

**Table 25 – Annual Street Light Fixture Costs**

| | | 50 W HP S | 100 W HP S |
|---|---|---|---|
| | | ------- (2006 BBD$ | per Fixture) ------ |
| Investment - Street Lights | | (1) | (2) |
| (1) | Investment per Fixture | $233.27 | $225.01 |
| (2) | Assembly and Installation Costs | 80.83 | 80.83 |
| (3) | Total Investment per Fixture (1)+(2) | 314.10 | 305.84 |
| (4) | With General Property Loading (3) x 1.0933 | 255.04 | 246.01 |
| (5) | Annual Economic Charge Related to Capital Investment | 8.49% | 8.49% |
| (6) | A&G Loading (Plant Related) | 0.59% | 0.59% |
| (7) | Total Carrying Charge (5) + (6) | 9.08% | 9.08% |
| (8) | Annualized Street Light Costs (4) x (7) | 23.16 | 22.34 |
| O&M - Street Lights | | | |
| (9) | Street Light O&M Expenses | 25.34 | 25.34 |
| (10) | With A&G Loading (9) x 1.2456 (Non-plant Related) | 31.56 | 31.56 |
| (11) | Subtotal (8) + (10) | 54.72 | 53.90 |
| | Working Capital | | |
| (12) | Materials and Spares (3) x 1.70% | 4.34 | 4.18 |
| (13) | Prepayments (3) x 0.430% | 1.10 | 1.06 |
| (14) | Cash Working Capital (10) x 12.50% | 3.95 | 3.95 |
| (15) | Revenue Requirement for Working Capital [(12)+(13)+(14)] x 6.00% | 0.56 | 0.55 |
| (16) | Total Annual Marginal Fixture-Related Costs (11) + (15) | $55.29 | $54.45 |

# VI. Other Marginal Costs

## A. Customer Service Expenses

When customers are added, BL&P faces higher costs for customer service expenses such as meter reading, collection and inspection, billing, and bad debts. We calculated the level of these expenses per weighted customer in the past five years, with weights based on information supplied by BL&P regarding the level of such expenses for each customer class. We used the average over five years as the estimate of marginal customer service expense per customer, and then multiplied this amount by the class weights to develop marginal expense levels for each class. These calculations are shown on Tables 26 and 27.

**Table 26 – Customer Service Expenses per Weighted Customer**

| | | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|---|
| (1) | Customer Service Expenses (Thousand BBD$) | $5,942.63 | $6,115.63 | $6,733.96 | $6,660.03 | $7,036.47 |
| (2) | Customers | 105,195 | 107,232 | 109,488 | 111,743 | 113,720 |
| (3) | Weighted Number of Customers (2) x 0.996 | 104,762 | 106,790 | 109,037 | 111,283 | 113,252 |
| (4) | Expense Per Weighted Customer (BBD$) [(1) / (3)] x 1000 | $56.73 | $57.27 | $61.76 | $59.85 | $62.13 |
| (5) | Labor Cost Index (2006 = 1.00) | 0.83 | 0.86 | 0.89 | 0.92 | 0.96 |
| (6) | Expense Per Weighted Customer in 2006 BBD$ (4) / (5) | $68.68 | $66.65 | $69.36 | $65.36 | $64.89 |
| (7) | Estimated Annual Expense Per Weighted Customer (2006 BBD$) (Average of 2001-2005) | | | $66.99 | | |

**Table 27 – Customer Service Expenses per Customer**

| | Class | Weighting Factor | Annual Customer Service Expense Per Customer |
|---|---|---|---|
| | | | (2006 BBD$) |
| | | | (1) x $66.99 |
| | | (1) | (2) |
| (1) | Domestic | 1.00 | $66.99 |
| (2) | General Service | 0.99 | $66.22 |
| (3) | Secondary | 0.94 | $62.98 |
| (4) | Large Power | 0.69 | $45.90 |

## B. Administrative and General Expenses and General Property

When a utility adds plant and incurs additional O&M expenses, it typically incurs additional overhead costs as well. A given element of administrative and generation (A&G) expense can grow with plant or with O&M expenses, or remain constant. General property typically grows with other types of plant. Our marginal cost study includes loaders for general property and A&G expenses, shown on Table 28, to capture these elements of marginal cost.

### 1. Administrative and General Expenses

Based on our discussions with BL&P, these expenses were divided into two categories: (1) those associated with other types of expenses ("non-plant related A&G") and (2) those associated with plant ("plant-related A&G").

Non-plant related A&G expenses include:

Supervision

General Office Expenses

Legal

Welfare and Training

Maintenance of Buildings and Structures

Systems Development

Marketing and Communications

Information Systems (less 50% of Software Licenses, Hardware Maintenance, and Mapping/Website Maintenance)

These expenses for the period 2001 – 2005 were divided by the corresponding amount of total O&M (less fuel, insurance and property tax, and A&G). The average ratio for the past three years was used in the study, with a small adder for Employer's Liability Insurance costs.

Plant-related expenses include:

Regulatory Board Expenses

Corporate Services

Quality Improvement

Studies

Engineering and Planning

50% of the certain Information Systems expenses (Software Licenses, Hardware Maintenance, and Mapping/Website Maintenance)

These expenses were divided by total plant, stated in Replacement Cost New, to create a loader for incremental plant. In this case the average ratio for the entire five-year period was used in the study. Factors to account for property insurance were added to the loaders applicable to various types of plant.

## 2. General Property

General property consists of items such as office buildings, warehouses, transport and other furniture and equipment. When a utility adds generation, transmission and distribution equipment, its need for general property increases as well. To account for the marginal cost of general property we estimated a general property loading factor applicable to other marginal plant. For each of the past five years we divided general property (replacement cost new) by total plant less general property (replacement cost new). We used the average for the period 2003-05 in our estimate of marginal general property loader. An estimate of property insurance costs for each type of plant was added to the general property loader.

**Table 28 – Loading Factors for Administrative and General Expenses and General Property**

| | | Estimate of Loading Factor |
|---|---|---|
| | **Administrative and General Expenses** | |
| (1) | Applicable to Non-Plant-Related Expenses | 24.56% |
| | Applicable to Plant-Related Expenses | |
| (2) | For generation, including property insurance | 1.0% |
| (3) | For transmission including property insurance | 2.3% |
| (4) | For distribution feeders and local facilities, including property insurance | 2.4% |
| (5) | For distribution substations, including property insurance | 0.6% |
| (6) | **General Property** | 9.33% |

## C. Fuel Stock and Working Capital

One of the elements of marginal energy cost is the cost of financing the additional fuel stock required as load grows. We estimated this factor from the value of the average fuel stock per dollar of fuel consumed in 2005.

Working capital consists of cash, materials, spares and prepayments. The cash component is a function of the difference in timing of the utility's payments to its suppliers, and its customers' payments of their bills. We assumed that BL&P requires cash working capital equal to 1/8 of its O&M, which assumes a 1.5-month lag. We estimated the materials, spares and prepayments elements of working capital from the relationship between these elements and total plant (at replacement cost new) in recent years.

## D. Marginal Losses

Marginal demand loss factors related to the expansion of the physical system are based on total losses at system peak. Total losses include both fixed losses associated predominantly with transformer cores, and variable losses associated with conductors.

To supply an added kW at a customer meter, each component above that meter must accommodate that kW plus all the added losses that will occur from that meter, up to and including that component.[6] The demand loss factors used in this study were developed from the losses in the 1997 embedded cost study.

Marginal energy losses are incurred by moving an additional kWh through the fixed system in a particular hour. Fixed losses are, by definition, not affected by marginal increments in load. Only variable losses come into these calculations. Marginal energy losses increase in proportion to the square of the load. We calculated marginal energy losses by period using a formula that reflects this quadratic dependence and is a function of variable losses at system peak, load at system peak, and hourly loads.

[6] The marginal demand loss factor for an individual component is the ratio of the input to the output from that component at time of peak. The capacity adjustment for a component up-stream of a customer meter is the product of all the loss factors including that of component itself.

# VII. Computation of Carrying Charges

To be useful in ratemaking and other marginal cost applications, the marginal investment in new plant must be converted into annual costs using an economic carrying charge. These annual charges reflect the ownership costs of BL&P's incremental plant: return to "stockholders" and bondholders, depreciation, income taxes and property taxes.

For use in a marginal cost study, the appropriate stream of annual charge is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. It is helpful to think of this stream as a series of rental charges that an entrepreneur in a competitive industry would charge for the use of utility equipment. The rental charges would rise as inflation made the equipment more valuable, but tend to decline as technological improvements made newer equipment more attractive to renters. The present value of the entire stream would have to be sufficient to cover the entrepreneur's ownership costs, or the investment would never take place. On the other hand, competition would keep the entrepreneur from charging more than the cost of ownership (including a fair return on the investment). In such a stream of rental charges, the first year's charge represents the cost in today's dollars of making the plant or equipment available for a year. These first-year charges are shown on Table 29.

**Table 29 – Economic Carrying Charges**

| | | Low Speed Diesel (1) | T&D Stations (2) | Transmission Lines (3) | Distribution Facilities (4) | Meters (5) | Services (6) | Street Lights (7) |
|---|---|---|---|---|---|---|---|---|
| (1) | Present Value of Revenue Requirements Related to Incremental $1,000 Investment | 950.35 | 1,117.36 | 1,068.22 | $938.24 | $925.54 | 1,009.24 | 851.78 |
| (2) | Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment | 0.00 | (3.81) | (25.06) | $3.75 | $8.66 | 17.65 | 4.82 |
| (3) | Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2) | $950.35 | $1,113.55 | $1,043.16 | $941.99 | $934.20 | $1,026.89 | $856.60 |
| (4) | First-Year Annual Economic Charge Related to Incremental $1,000 Investment | 46.01 | 53.91 | 55.82 | $63.86 | $60.84 | 76.08 | 84.93 |
| (5) | First-Year Annual Economic Charge Related to Incremental Investment [(4)/$1,000] | 4.60% | 5.39% | 5.58% | 6.39% | 6.08% | 7.61% | 8.49% |

One major element of the ownership cost of utility equipment is the cost of capital. BL&P has two potential sources of capital—debt and equity. For the next few years, BL&P plans to finance all incremental investment with debt. For the incremental cost of debt we used 6 percent.

An integral part of the economic carrying charge calculation is the estimation of the rate of inflation net of technical progress applicable over the life of the investment. While it is never easy to peg an exact rate of long-term future inflation or technical progress, we have used a rate of two percent.

Another component of the economic carrying charge is an adjustment for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. Line 2 of Table 29 above shows the adjustment for this dispersed pattern of replacements.

# VIII. Summary Schedules

Table 30 summarizes the time-differentiated marginal energy costs per kWh and marginal generation, transmission and distribution capacity costs per kW for 2006. The generation capacity and energy components will be different (in real terms) in other years. Because street lights do not operate during the defined peak hours, no capacity costs are listed for that class.

Note that costs stated on a per-kW basis are not necessarily what a utility would use to set demand charges. These marginal demand-related costs are simply the sum of the hourly costs. Thus the utility's costs would increase by this amount only if the customer increased load by one kilowatt in every hour of the period. If a customer's increase in load at the time of his seasonal peak were not matched by the same increase in all other hours of the period, an efficient demand charge would be a weighted sum of the hourly costs, not the sum of those costs. The appropriate weights would be each hour's load change relative to the customer's load change in the seasonal peak hour.

An alternative to recovering generation, transmission and distribution substation/feeder capacity costs on the basis of a customer's monthly peak demand is to charge for this capacity on a time-differentiated per kWh basis. Table 31 converts the capacity costs to a cost per kWh by period.

**Table 30 – Summary of Time-Varying 2006 Marginal Costs**

| | | Peak | Off-Peak |
|---|---|---|---|
| | | (2006 BBD$) | |
| | | (1) | (2) |
| | Large Power | | |
| (1) | Energy (per kWh) | $0.2946 | $0.2038 |
| (2) | Generation Capacity (per peak period kW-mo.) | $1.30 | |
| (3) | Transmission (per peak period kW-mo.) | $1.66 | |
| (4) | Distribution Substation (per peak period kW-mo.) | $4.03 | |
| | Total per kW | $6.99 | |
| | Secondary Voltage | | |
| (5) | Energy (per kWh) | $0.3033 | $0.2085 |
| (6) | Generation Capacity (per peak period kW-mo.) | $1.32 | |
| (7) | Transmission (per peak period kW-mo.) | $1.69 | |
| (8) | Distribution Substation (per peak period kW-mo.) | $4.10 | |
| | Total per kW | $7.11 | |
| | General Service | | |
| (9) | Energy (per kWh) | $0.3033 | $0.2085 |
| (10) | Generation Capacity (per peak period kW-mo.) | $1.32 | |
| (11) | Transmission (per peak period kW-mo.) | $1.69 | |
| (12) | Distribution Substation (per peak period kW-mo.) | $4.10 | |
| | Total per kW | $7.11 | |
| | Domestic | | |
| (13) | Energy (per kWh) | $0.3033 | $0.2085 |
| (14) | Generation Capacity (per peak period kW-mo.) | $1.32 | |
| (15) | Transmission (per peak period kW-mo.) | $1.69 | |
| (16) | Distribution Substation (per peak period kW-mo.) | $4.10 | |
| | Total per kW | $7.11 | |
| | Street Lights | | |
| (17) | Energy (per kWh) | $0.3033 | $0.2085 |
| (18) | Generation Capacity (per peak period kW-mo.) | NA | |
| (19) | Transmission (per peak period kW-mo.) | NA | |
| (20) | Distribution Substation (per peak period kW-mo.) | NA | |
| | Total per kW | NA | |

**Table 31 – Summary of Time-Varying 2006 Marginal Costs per kWh**

| | | | Peak | Off-Peak |
|---|---|---|---|---|
| | | | ------ (2006 BBD$ per kWh) ---- | |
| | | | (1) | (2) |
| | Large Power | | | |
| (1) | | Energy | $0.2946 | $0.2038 |
| (2) | | Generation Capacity | $0.0100 | |
| (3) | | Transmission | $0.0128 | |
| (4) | | Distribution Substation | $0.0310 | |
| | | Total | $0.3484 | $0.2038 |
| | Secondary | | | |
| (5) | | Energy | $0.3033 | $0.2085 |
| (6) | | Generation Capacity | $0.0102 | |
| (7) | | Transmission | $0.0130 | |
| (8) | | Distribution Substation | $0.0315 | |
| | | Total | $0.3580 | $0.2085 |
| | General Service | | | |
| (9) | | Energy | $0.3033 | $0.2085 |
| (10) | | Generation Capacity | $0.0102 | |
| (11) | | Transmission | $0.0130 | |
| (12) | | Distribution Substation | $0.0315 | |
| | | Total | $0.3580 | $0.2085 |
| | Domestic | | | |
| (13) | | Energy | $0.3033 | $0.2085 |
| (14) | | Generation Capacity | $0.0102 | |
| (15) | | Transmission | $0.0130 | |
| (16) | | Distribution Substation | $0.0315 | |
| | | Total | $0.3580 | $0.2085 |
| | Street Lights | | | |
| (17) | | Energy | $0.3033 | $0.2085 |
| (18) | | Generation Capacity | NA | |
| (19) | | Transmission | NA | |
| (20) | | Distribution Substation | NA | |
| | | | $0.3033 | $0.2085 |

Table 32 summarizes the monthly customer-related and distribution facilities costs by class.

**Table 32 – Summary of Monthly Marginal Customer-related and Distribution Facilities Costs**

| | Customer Class | Monthly Facility Cost per kVA of Design Demand | Estimate of Typical Design Demand by Customer | Monthly Facility Cost per Customer | Monthly Marginal Customer Cost per Customer |
|---|---|---|---|---|---|
| | | (BBD$/kVA) | (kVA) | (BBD$/customer/mo.) | |
| | | (1) | (2) | (3) (1)*(2) | (4) |
| (1) | Domestic | $6.82 | 3.51 | $23.91 | $9.79 |
| (2) | General Service | 6.82 | 3.51 | 23.91 | $11.30 |
| (3) | Secondary | 3.19 | | | $14.20 |
| (4) | Large Power | 0.69 | | | $119.70 |

Table 33 summarizes the monthly street light costs, both fixture costs and distribution facilities costs.

**Table 33 – Monthly Street Light Fixture and Distribution Facilities Costs**

| | Customer Class | Monthly Cost per Fixture | Monthly Facility Cost per kVA of Design Demand | Estimate of Typical Design Demand | Monthly Distribution Facility Cost per Fixture | TOTAL Monthly Cost Per Fixture |
|---|---|---|---|---|---|---|
| | | (BBD$) | (BBD$) | kVa | (BBD$) | (BBD$) |
| | | (1) | (2) | (3) | (4) (2)*(3) | (5) (1)+(4) |
| (1) | 50 W HPS | $4.61 | $6.82 | 0.08 | $0.55 | $5.16 |
| (2) | 100 W HPS | $4.54 | 6.82 | 0.18 | $1.25 | $5.79 |

# Appendix A

**Rationale for Adjustments to Annual Cost of New Generating Capacity**

Prudent planning for generation capacity expansion involves a trade-off between cost and reliability. Customers want reliable service, but are not willing to pay prices that guarantee no generation-related outages. Utilities set reliability standards that reflect consumers' willingness to pay for reliability. BL&P's standard is one day's outage per year – or 24 loss-of-load hours (LOLH). The Company adds capacity as needed to meet this standard. However, given the isolation of the system and the lumpiness of capacity additions, reliability is typically greater than the target level for a few years after each new generation addition. In those years, marginal load does not trigger another generation addition, but does affect reliability of the system to some degree, by increasing LOLH above what otherwise would have occurred.

The cost of the added LOLH depends upon the cost to consumers of unserved energy. Although it is difficult to measure the cost of unserved energy (CUE), it is easy to back into the CUE that is implicit in the utility's reliability target.

If we assume that the reliability target (LOLH*) is set based on an accurate assessment of the CUE, then it must be true that in a year when actual LOLH = LOLH*, the system is optimal and the benefits of the last (or next) kW of capacity is just equal to the cost of the last (or next) kW of capacity. These benefits are the outage costs avoided because of the presence of the last kW of capacity; *i.e.*, CUE times LOLH*, multiplied by one minus the effective forced outage rate of the marginal kW of capacity, because there is probability that it will be forced out in some of the hours when it is needed to supply load. The cost of that marginal kW of capacity is the annual cost of a kW of peaking capacity (ACC), or of another type of capacity less the fuel savings it will provide in other hours.

Benefit of marginal kW = Cost of marginal kW

$$(1\text{-EFOR}) \times CUE \times LOLH^* = ACC$$

Solving for CUE gives the value of CUE implicit in the reliability target.

$$CUE = [ACC / (1\text{-EEFOR})]/LOLH^*$$

In any given year, when LOLH may not be equal to LOLH*, the annual marginal cost of capacity is:

$$LOLH \times CUE = [ACC / (1\text{-EFOR})] \times [LOLH / LOLH^*].$$

Thus, the annual marginal cost of generation in any year is the annual cost of the least-cost capacity option, adjusted for its effective forced outage, times the ratio of expected to target LOLH.

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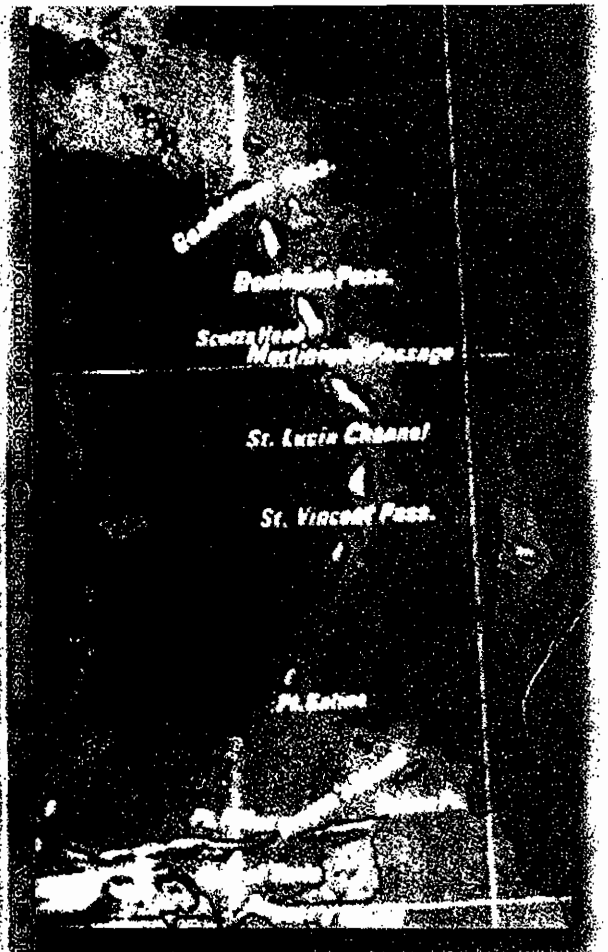


# JOURNAL OF EASTERN CARIBBEAN STUDIES

Vol. 31 No. 1 March, 2006

The Journal of Eastern Caribbean Studies (JECS) is the leading social science journal covering the Eastern Caribbean area. It is published quarterly by the Sir Arthur Lewis Institute of Social and Economic Studies, University of the West Indies, Cave Hill Campus, in March, June, September and December. Established in 1975 as the **Bulletin of Eastern Caribbean Affairs**, it was upgraded to a full peer review academic journal from Volume 22, 1997. The **JECS** is concerned with analytical commentaries on political, social, economic, business and environmental developments in the Caribbean with special emphasis on the Eastern Caribbean and small states.

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**Vol. 31 No.1** — **March 2006**

*Thin Trading and Limitations on Share Repurchases*

Despite the efforts of the BSE and successive governments in Barbados, trading on the BSE is extremely thin, and in the absence of major corporate restructurings such as mergers and acquisitions, only a very small percentage of shares change hands each year (see Table 2). This may in part be due to the relatively underdeveloped market microstructure. Transactions costs are relatively high, there a limited number of trading days on the exchange (for most of its life the exchange only traded two days a week, a third day has recently been added) and market makers are conspicuously absent. However, the low trading levels may also be influenced by the pattern of shareholding described in the previous sub-section.

**Table 2: Level of Trading On The BSE**

| | Total Volume of Shares Outstanding | % Traded |
|---|---|---|
| 1988 | 155 | 0.76% |
| 1989 | 178 | 0.69% |
| 1990 | 181 | 0.60% |
| 1991 | 198 | 1.05% |
| 1992 | 195 | 0.85% |
| 1993 | 210 | 1.35% |
| 1994 | 234 | 0.91% |
| 1995 | 239 | 0.70% |
| 1996 | 254 | 1.00% |
| 1997 | 228 | 1.43% |
| 1998 | 256 | 1.95% |
| 1999 | 303 | 0.79% |
| 2000 | 3070 | 0.63% |

Source: BSE website

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April 3, 2008

FOR IMMEDIATE RELEASE

**JOINT MEDIA RELEASE BY THE GOVERNMENT OF THE CAYMAN ISLANDS AND CARIBBEAN UTILITIES COMPANY, LTD. (CUC).**

**THE CLASS A ORDINARY SHARES OF CARIBBEAN UTILITIES COMPANY, LTD. ARE LISTED FOR TRADING IN UNITED STATES FUNDS ON THE TORONTO STOCK EXCHANGE/TRADING SYMBOL: CUP.U**

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# GOVERNMENT AND CUC ANNOUNCE THE SIGNING OF ELECTRICITY LICENCES

GRAND CAYMAN, CAYMAN ISLANDS- The Cayman Islands Government ("Government") and Caribbean Utilities Company, Ltd. ("CUC") announced today, the signing of an exclusive Electricity Transmission and Distribution Licence (the "T&D Licence") and a non-exclusive Electricity Generation Licence (the "Generation Licence") for operations in Grand Cayman. The terms of the licences were outlined in an Agreement in Principle ("AIP") dated and announced December 20, 2007 and remain substantially the same.

The non-exclusive Generation Licence is for a term of 21.5 years. The recently amended Electricity Regulatory Authority Law (2005 Revision) provides for the conduct of a competitive bid process to be managed by the Electricity Regulatory Authority ("ERA") for new generating capacity and for the replacement of retired generating capacity. The first such competitive process under this licence is expected to begin later this year with the filing of the Certificate of Need by CUC for the calendar years 2011 and 2012.

The exclusive T&D Licence is for an initial term of 20 years with a provision for automatic renewal unless either party gives notice to terminate.

The December 20, 2007 AIP announcement outlined the Rate Cap Adjustment Mechanism ("RCAM") which is designed to maintain the CUC Return On Rate Base ("RORB") in the target 9 to 11% range. Under the RCAM, base rate adjustments will be considered annually based on a combination of Cayman Islands and US consumer price index ("CPI") movements defined as the Price Level Index. As a refinement to the previously announced RCAM, the parties have further agreed that, in the year following a natural disaster such as a hurricane where the Governor has declared a state of emergency and the Cayman Islands CPI doubles, CUC's base

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rate adjustments will be limited to 60% of the Price Level Index. Any residual base rate adjustment for that year that would otherwise be permitted by the full application of RCAM would be carried over and applied in addition to the normal RCAM adjustment in either of the next two years if CUC's RORB is below the target RORB range.

Upon the execution of the new licences, the Government nominated directors on the CUC Board of Directors will resign and those vacancies will not be filled with Government nominated directors at the next CUC shareholders' meeting.

On behalf of Government, the Minister of Infrastructure and Communications, the Honourable Arden McLean, stated that "This is an historic day in the provision of electric power for Grand Cayman Island. Consumer rates for power have already come down substantially as of January of this year and the hurricane recovery surcharge was removed completely. Working with CUC, we have provided in these documents for a solid long-term framework for the further benefit of consumers, in which we will control rate increases; maintain reliability; introduce competition in generation; require performance standards; strongly encourage renewables; ensure proper regulatory oversight; enhance environmental protection; and encourage efficiency. This will all be done while also providing for CUC's continued financial health. I would like to express my appreciation for the continued support of the Leader of Government Business, the Cabinet and the hard work of the negotiating teams that have brought us to this point."

CUC President and Chief Executive Officer Mr. Richard Hew said, "I am pleased to be a part of the achievement of this important milestone in CUC and Grand Cayman's history. The new licences and regulatory structure provide the level of certainty required for CUC to execute the long-term plans and make financial commitments necessary to ensure that residents and businesses in Grand Cayman can continue to look forward to a highly reliable and efficient electricity service. I would like to thank our resigning directors, Philip Barnes, Sheree Ebanks and Anna Rose Washburn, for their dedication and input throughout their tenure as company directors. Finally, I would like to thank the many persons who have contributed significant time and effort to realize the positive outcome of the negotiations."

*Caribbean Utilities Company, Ltd., on occasion, includes forward-looking statements in its media releases, Canadian securities regulatory authorities filings, shareholder reports and other communications. Forward-looking statements include statements that are predictive in nature, depend on future events or conditions, or include words such as "expects", "anticipates", "plan", "believes", "estimates", "intends", "targets", "projects", "forecasts", "schedule", or negative versions thereof and other similar expressions, or future or conditional verbs such as "may", "should", "would" and "could". Forward-looking statements are based on underlying assumptions by their very nature and are subject to certain risks and uncertainties that may cause actual results to vary from plans, targets and estimates. Such risks and uncertainties include but are not limited to general economic, market and business conditions, regulatory developments and weather conditions. CUC cautions readers that actual*

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*results may vary significantly from those expected should certain risks or uncertainties materialize or should underlying assumptions prove incorrect. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.*

**For further information on this announcement please contact:**

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17 June 2005

# Independent Expert Report on Belize Electricity Full Tariff Review Proceedings, 2005

Dennis Colenutt

NERA
Economic Consulting

**Privileged and Confidential**

MMC Marsh & McLennan Companies

the Interim Decision, it seems to me that Mollejon is not a matter that comes within the scope of my review.

### 2.9.3. Findings and Recommendations

I estimate BEL's cost of capital using the weighted average cost of capital (WACC) approach, and I recommend that this WAC be used as the ROR for BEL. The WACC methodology states that the cost of capital is calculated as the weighted average of the cost of debt and the cost of equity, weighted by the market values of debt and equity (or gearing). This is the same approach as employed by BEL and the PUC.

A detailed derivation of BEL's WACC can be found in Table 2.4 below, which also summarises my results. A summary of the methodology employed in estimating individual parameters is below:

- ***Real vs. nominal WACC:*** The WACC is being applied to a non-index-linked Regulatory Asset Value and therefore it is appropriate to use a nominal WACC estimate. My estimate of BEL's nominal pre-tax WACC is 12.4%.
- ***Gearing:*** I estimate BEL's gearing level of 49% by using BEL's forecast gearing level of 49% (averaged over 2004-2009[11]).
- ***Cost of debt:*** I estimate BEL's cost of debt of 8.76% based on BEL's current and forward-looking debt costs.[12] Alternative, more reliable, approaches could not be taken due to lack of available data.
- ***Cost of equity:*** I use a CAPM approach where:
  - I estimate an asset beta of 0.4 based on regulatory precedents for electricity utilities operating in comparable price cap regulatory regimes and by examining direct asset beta estimates for comparable utilities operating in Latin and Central America.
  - I estimate an Equity Risk Premium of 6.7% using a long-term historical world average of returns on equity relative to bonds from LBS/ABN Amro. This approach is widely used by international regulators.
  - I estimate a country risk premium of 4.6% based on 3-months average sovereign debt spreads over the appropriate US government bonds for sovereign debt (Argentina and Venezuela) with B/CCC+ credit rating.

Key differences between my approach and BEL's are as follows:

- ***Higher cost of equity:*** My estimate of the pre-tax cost of equity of 15.82% is higher than BEL's estimate of 11.63%. This is primarily due to 1) my asset beta assumption of 0.4 being higher than BEL's assumption of 0.25 and 2) my methodology for estimating the country risk premium being based on sovereign debt spreads and not Eximbank exposure fees methodology adopted by BEL.

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[11] Source: "05-09 BusPlan (PUC) FTRPVer 7 (PUCRevisedRSARecovenies) (PUC).xls".

[12] Source: "LTDForecastedAnalysis.xls".

- ***Slightly lower cost of debt:*** My estimate of the cost of debt of 8.76% is slightly lower than BEL's estimate of 8.96%. I incorporated forecast debt costs as well as current debt costs whereas BEL's estimate is based on historic book values of debt only.
- ***Gearing:*** I estimated BEL's gearing level of 49% using BEL's financial model as this results in a forward-looking estimate.[13]
- ***Premium for other business risks:*** I do not include a risk premium for other business risks as CAPM already accounts for business risk within its parameters.

- PUC estimate BEL's WACC based on historic debt costs and historic returns to equity.

With regard to the range, the purpose of the allowed range of variation is to provide some incentive to the licensee to improve its performance, while also allowing providing relief for consumers where the return rises too high and protecting the licensee where it falls too low. BEL's objection relates to the lower boundary. In that case, it is clearly essential that the bottom of the range of return allowed must, as an absolute minimum, be sufficient to allow the utility to continue to service its borrowings. In addition, some level of return should be allowed to shareholders, if the licensee is to be able to continue to finance its activities. I therefore recommend that the values should be:

| | |
|---|---|
| $ROR_{min}$ | 10.0% |
| $ROR_{max}$ | 15.0% |

In addition, I would also recommend that PUC considers specifying the maximum and minimum values in terms of post-tax returns, to allow for any changes in tax rates during the FTRP period.

13 Source: "05-09 BusPlan (PUC) FTRPVer 7 (PUCRevisedRSARecovenies) (PUC).xls".

## Table 2.4
## Independent Expert Estimate of BEL's WACC

| Parameter | NERA Estimate | BEL (S&W) | NERA Methodology |
|---|---|---|---|
| a. Tax rate | 8% | 8% | BEL's corporate tax rate (average over 2004-2009, source = BEL's financial forecasts for PUC) |
| b. Gearing (D/(D+E)) | 49% | 57% | Average over 2004-2009, source = BEL financial forecasts for PUC |
| c. D/E | 0.96 | 1.33 | = b/(1-b) |
| d. Belize forward-looking inflation rate | 2.80% | 2% | IMF International Economic Outlook, September 2004 |
| e. US forward-looking inflation rate | 2.90% | 2% | Differential in 3-month average yield to maturity on a 30-year non-indexed US bond relative to an equivalent indexed one |
| f. Nominal US risk free rate | 4.70% | 3.5% | 30-year US Treasury 3-months average yield to maturity |
| g. Belize country risk premium | 4.60% | 3.54% | 3-months average yield to maturity of 2 CCC+ rated Argentinean bonds and 1 B rated Venezuelan bond |
| h. Currency risk premium | (-0.1%) | 0% | = d-e |
| i. Belize nominal US$ risk free rate | 9.30% | 7.04% | =f+g |
| j. Belize nominal risk free rate (Bz$) | 9.20% | 7.04% | =h+i |
| k. ERP | 6.70% | 6.3% | World long term average historical ERP |
| l. Asset beta | 0.40 | 0.25 | |
| m. Equity beta | 0.78 | 0.58 | =l*(1+c) |
| n. Nominal US$ post-tax cost of equity | 14.55% | 10.70% | = (m*k)+i |
| o. Nominal US$ pre-tax cost of equity | 15.82% | 11.63% | = n/(1-a) |
| p. Nominal post-tax cost of equity (Bz$) | 14.45% | 10.70% | =(m*k)+(h+i) |
| q. Nominal pre-tax cost of equity (Bz$) | 15.71% | 11.63% | =p/(1-a) |
| f. US risk free rate | 4.70% | 3.5% | |
| h. Currency risk premium | (-0.1%) | 0% | |
| r. BEL Debt Premium | 4.06%[2] | 5.46% | Company bond spread for B- rated utilities |
| s. BEL Nominal US$ cost of debt | 8.76% | 8.96% | =f+r |
| t. BEL Nominal cost of debt (Bz$) | 8.66% | 8.96% | =s+h |
| u. Nominal US$ post-tax WACC | 11.4% | 9.30%+2.9%=12.2%[1] (2.9% = "Business Risk Premium") | =(n*(1-b))+(s*b*(1-a)) |
| **v. Nominal US$ pre-tax WACC** | **12.4%** | **10.11%+2.9%=13.0%** | **=o*(1-b)+s*b** |
| w. Real post-tax US$ WACC | 8.3% | 7.16%+2.9%=10.1%[1] | =((u+1)/(1+d))-1 |
| x. Real pre-tax US$ WACC | 9.0% | 7.95%+2.9%=10.8%[1] | =((v+1)/(1+d))-1 |

*NERA analysis.*

*(1) S&W add an additional risk premium to the overall WACC of 2.9%.*

*(2) Implied debt premium based on the overall cost of debt of 8.76% and the risk free rate of 4.7%.*

## Appendix A. Detailed Rate of Return Analysis

To estimate BEL's cost of capital we have used the weighted average cost of capital (WACC) approach. The WACC methodology states that the cost of capital is calculated as the weighted average of the cost of debt and the cost of equity, weighted by the market values of debt and equity (or gearing). This is the same approach as employed by BEL and the PUC.

The table below summarises our results.

## Table A.1
## NERA Estimate of BEL's WACC

| Parameter | NERA Estimate | BEL (S&W) | NERA Methodology |
|---|---|---|---|
| a. Tax rate | 8% | 8% | BEL's corporate tax rate (average over 2004-2009, source = BEL's financial forecasts for PUC) |
| b. Gearing (D/(D+E)) | 49% | 57% | Average over 2004-2009, source = BEL financial forecasts for PUC |
| c. D/E | 0.96 | 1.33 | = b/(1-b) |
| d. Belize forward-looking inflation rate | 2.80% | 2% | IMF International Economic Outlook, September 2004 |
| e. US forward-looking inflation rate | 2.90% | 2% | Differential in 3-month average yield to maturity on a 30-year non-indexed US bond relative to an equivalent indexed one |
| f. Nominal US risk free rate | 4.70% | 3.5% | 30-year US Treasury 3-months average yield to maturity |
| g. Belize country risk premium | 4.60% | 3.54% | 3-months average yield to maturity of 2 CCC+ rated Argentinean bonds and 1 B rated Venezuelan bond |
| h. Currency risk premium | (-0.1%) | 0% | = d-e |
| i. Belize nominal US$ risk free rate | 9.30% | 7.04% | =f+g |
| j. Belize nominal risk free rate (Bz$) | 9.20% | 7.04% | =h+i |
| k. ERP | 6.70% | 6.3% | World long term average historical ERP |
| l. Asset beta | 0.40 | 0.25 | |
| m. Equity beta | 0.78 | 0.58 | =l*(1+c) |
| n. Nominal US$ post-tax cost of equity | 14.55% | 10.70% | = (m*k)+i |
| o. Nominal US$ pre-tax cost of equity | 15.82% | 11.63% | = n/(1-a) |
| p. Nominal post-tax cost of equity (Bz$) | 14.45% | 10.70% | =(m*k)+(h+i) |
| q. Nominal pre-tax cost of equity (Bz$) | 15.71% | 11.63% | =p/(1-a) |
| f. US risk free rate | 4.70% | 3.5% | |
| h. Currency risk premium | (-0.1%) | 0% | |
| r. BEL Debt Premium | 4.06%[2] | 5.46% | Company bond spread for B- rated utilities |
| s. BEL Nominal US$ cost of debt | 8.76% | 8.96% | =f+r |
| t. BEL Nominal cost of debt (Bz$) | 8.66% | 8.96% | =s+h |
| u. Nominal US$ post-tax WACC | 11.4% | 9.30%+2.9%=12.2%[1] (2.9% = "Business Risk Premium") | =(n*(1-b))+(s*b*(1-a)) |
| **v. Nominal US$ pre-tax WACC** | **12.4%** | **10.11%+2.9%=13.0%** | **=o*(1-b)+s*b** |
| w. Real post-tax US$ WACC | 8.3% | 7.16%+2.9%=10.1%[1] | =((u+1)/(1+d))-1 |
| x. Real pre-tax US$ WACC | 9.0% | 7.95%+2.9%=10.8%[1] | =((v+1)/(1+d))-1 |

*NERA analysis.*

*(1) S&W add an additional risk premium to the overall WACC of 2.9%.*

*(2) Implied debt premium based on the overall cost of debt of 8.76% and the risk free rate of 4.7%.*

## A.1. WACC Methodology

### A.1.1. WACC Formula

It is an established regulatory principle that the appropriate Rate of Return to use in setting regulated tariffs is the cost of capital of the company. The cost of capital is defined as the minimum expected rate of return that will allow the regulated company to attract funds. Regulated tariffs that are based on an expected return equal to the cost of capital will therefore ensure that the company is allowed to earn normal profits, thus mimicking the outcome of a competitive market.

The standard methodology used to estimate the cost of capital of a company is known as the WACC methodology. The WACC methodology estimates the cost of capital as the weighted average of the cost of equity and cost of debt of the company as follows:

$$\text{Post-Tax WACC} = r_e*(E/V)+r_d*(D/V)*(1-tc)$$

Where,

$r_e$ is the cost of equity;
$r_d$ is cost of debt;
D is a firm's debt;
E is a firm's equity; and
V is the total assets of the firm, that is, V =D+E. [16]

The pre-tax WACC is calculated by dividing the post tax WACC by the corporate (or effective) tax rate over the relevant period. We estimate both a post-tax WACC and a pre-tax WACC for BEL.

### A.1.2. Use of Comparators

In estimating the cost of equity the Capital Asset Pricing Model (CAPM) is widely employed to estimate companies' post-tax cost of equity. The CAPM is based on the theory that the required return on an asset is related to the asset's *systematic risk*, that is, the degree of co-movement between the company's returns and the market returns. This measure of systematic risk is known as the "beta" and can only be directly observed for quoted companies. For non-quoted companies, beta is either estimated indirectly by estimating beta risk for comparator companies or is inferred from regulatory precedent. BEL is not a quoted company and therefore its beta can only be estimated indirectly.

Appropriate comparator companies must face similar risks. Therefore in choosing comparators one needs to consider political, social, economic and financial environment that these companies operate in. This means that consideration must be given to assessment of country risk and types of operating contracts. Ideally, comparators need to be operating in the same sector however, information on operators in similar markets, such as other utilities, can still be useful.

[16] In the following we will refer to D/(D+E)=D/V as the "gearing" ratio of the company.

### A.1.3. Reference Market

From an investors' standpoint, the cost of capital should be estimated with reference to the financial market that best represents their investment opportunity set, as the cost of capital for any investment is calculated in relation to the whole portfolio of investment opportunities to which an investor has access. This "set" is commonly referred to as the "market portfolio".

In theory the "market portfolio" should include financially traded as well as non-traded assets. However, in practice WACC parameters are calculated with respect to readily available stock market indices, and therefore the "market portfolio" only captures financially traded assets traded on a stock exchange, to the exclusion of un-listed assets.

The next key question is whether in estimating a cost of capital for BEL, we should use a domestic stock market index, or regional or worldwide index. This is generally a question of the integration of the domestic economy with regional and worldwide economies.

Transactions, diversification, and taxation barriers to investment in some foreign securities by investors have eroded. It is now easier to purchase and sell shares traded on foreign exchanges. The purchase of ADRs and ADSs, for example, provides access to equity investments in foreign companies. However, some markets are still fairly self-contained and not fully integrated into the global securities market.

The government of Belize is supportive of foreign investment however procedures tend to be complicated by red tape. Several investment incentive schemes have been put in place but many investors still complain that these schemes are rarely as open and effective as the government claims.[17]

Because of these factors BEL's investor reference market is the domestic market. Specific allowance needs to be made for Belize specific factors such as country risk and currency risk.

## A.2. Cost of Equity

The post tax cost of equity is the return on equities (through dividends and through an increase in the value of shares) that is required to attract investors. To estimate the cost of equity a Capital Asset Pricing Model (CAPM) is commonly used by regulators throughout the world. This approach is also advocated by the World Bank in its recent guide on cost of capital calculation for infrastructure regulators. The CAPM is set out as:

$$E[r_e]=E[r_f]+\beta(E[r_m]-E[r_f])$$

*Where,*

- $E[r_e]$ is the expected return on equity
- $E[r_f]$ is the expected return on a risk free asset
- $E[r_m]$ is the expected rate of return for the market (and thus $E[r_m]-E[r_f]$ is the expected risk premium); and,
- $\beta$ is a measure of the systematic riskiness of the equity, the equity beta.

17 US Embassy, Belize: http://belize.usembassy.gov/wwwhinvestmentclimate.html#Openness.

The central tenet of CAPM is that investors hold a diversified portfolio of assets, and thereby diversify away the specific risk associated with assets. However, the portfolio still displays non-diversifiable risk, or *beta* risk, which is a measure of the co-movement of a particular asset or portfolio with the overall market portfolio. Beta risk is the only type of risk for which investors receive compensation in terms of higher returns. The cost of equity can then be interpreted as the risk-free rate plus a company specific risk premium.

### A.2.1. Risk Free Rate

One can usually estimate the risk-free rate by looking at yields for medium-long term government bonds issued by the country where a firm operates. However, the government bond market for debt in Belize is not well developed. It does not consist of a wide number of debt instruments, differentiated by the *maturity* and other debt characteristics (such as the coupon rate).

Given the lack of empirical data on Belizean government debt costs we do not use this evidence as the primary basis for estimating a risk free rate.

Our approach for estimating the risk free rate for Belize is based on the use a 30-year risk free rate for the US plus a country specific risk premium for Belize that reflects the sovereign credit rating of Belize. This gives a US$ denominated risk free rate. Conversion of this to a Belizean dollar denominated equivalent requires an addition of a currency risk premium defined as the difference between the long term Belizean rate of inflation and the long term US rate of inflation.

*US risk free rate*

Table A.2 shows that an average 3-months yield to maturity on a 30-year bond is 4.7% over 11 February to 11 May 2005 time period.

**Table A.2**
**US 30-Year Government Bond Yield**
**(normal maturity type, fixed coupon, US$ denominated, not index linked)**

| Ticker | Name | Maturity Date | Issue Date | Current Yield (%) | 3-Month Average Yield (%) |
|---|---|---|---|---|---|
| 912810FP Govt | US Treasury Bond | 15/02/31 | 15/02/01 | 4.525 | 4.674 |

*Source: NERA analysis of Bloomberg data as of 11/05/05.*

*Country Risk Premium*

We estimate Belize country risk premium by estimating 3-month average spreads on B/CCC+ rated sovereign bonds relative to appropriate US government bonds.

Belize has a Standard and Poor's (S&P) foreign currency credit rating of CCC-. Therefore it is appropriate to examine yields on bonds with that credit rating. However, two issues must be taken into account. The first issue is that there are very few countries in the world with a credit rating of CCC and we were only able to find three sovereign bonds with a credit rating similar to Belize. All three were issued by Argentina. The second issue is that Belize's credit rating has deteriorated significantly over the last year from its previous rating of B.

Arguably this deterioration is caused by short term factors and there is a significant chance that Belize's credit rating will improve over the forthcoming regulatory period. We therefore find it appropriate to consider evidence of bond yields with CCC and B credit rating.

Table A.3 gives 3-month average spreads for CCC+ rated Argentinean bonds over an appropriate US government bond. It shows 3-months spreads over an appropriate US government bond of between 4.4% and 4.9%. This premium over the US government bond reflects, among other factors, the probability of default by a particular government. An average of these spreads gives a country risk premium of 4.6%.

**Table A.3**
**Argentinean Bond Spreads over an Appropriate US Government Bond**

| Country | Maturity Date | Issue Date | Current Yield (%) | 3-Month Average Spread[1] | S&P Credit Rating |
|---|---|---|---|---|---|
| Argentina[1] | 11/04/2011 | 11/04/2002 | 8.972 | 4.884143 | CCC+ |
| Argentina[2] | 04/09/2018 | 28/10/2004 | 9.026 | 4.419327 | CCC+ |
| Venezuela[3] | 13/01/2034 | 14/01/2004 | 9.418 | 4.5475 | B |

*Source: NERA analysis of Bloomberg data as of 11/05/05.*
*(1) Euro denominated, maturity type = at maturity, coupon type = flat trading, not index linked.*
*(2) US$ denominated, maturity type = sinkable, coupon type = step, not index linked.*
*(3) US$ denominated, maturity type = sinkable, coupon type = fixed, not index linked.*
*(4) US$ denominated, maturity type = at maturity, coupon type = fixed, not index linked.*

We have crossed checked Argentinean bond spread against equally rated average corporate bond spread estimated by Reuters. Table A.4 presents Reuters spreads for CCC rated utility bonds. Given that corporate bonds of equal credit rating tend to incur a slightly higher premium, these are consistent with our country risk estimate.

**Table A.4**
**Reuters Corporate Spreads for CCC+ Rated Bonds (bsp)**

| | 1Y | 2Y | 3Y | 5Y | 7Y | 10Y | 30Y |
|---|---|---|---|---|---|---|---|
| Utilities | 580 | 650 | 755 | 710 | 495 | 520 | 620 |

*Source: www.bondsonline.com; November 2004.*

*Currency Risk Premium*

The currency risk premium is required to convert US$ denominated risk free rate to Belizean dollars denominated risk free rate. It is obtained by taking the difference between a long term Belizean rate of inflation and an equivalent long term US rate of inflation. We have used World Bank Development Indicators average growth rate of Consumer Price Index between 1981 and 2004[18] as the long-term rate of inflation.

*Risk Free Rate Conclusions*

18 World Bank Development Indicators only provide a Consumer Price Index for Belize from 1980 onwards.

We conclude that the US$ denominated risk free rate for Belize is equal to the US risk free rate plus a country risk premium. Therefore we take 3-months average 30-year maturity US government bond yield of 4.7% plus 3-months average spread for comparable B/CCC+ rated sovereign bonds over an appropriate US government bond of 4.6%. This gives us a Belizean nominal US$ denominated risk free rate of 9.3%.

To obtain a Belizean dollars denominated nominal risk free rate we take a US$ denominated risk free rate of 9.3% and add a currency risk premium of -0.1% to obtain a nominal risk free rate of 9.2%.

### A.2.2. Beta

One can estimate *quoted* companies betas (company specific risk) by observing their share price behaviour relative to the relevant stock market index. Because of concerns about the robustness of a single regression result, it is also common to compare a beta result with "comparator" companies who operate in the same economic sector and are likely to face similar business risks.

As BEL is not a quoted company, one cannot estimate its beta using direct market information. We therefore estimate a beta for BEL by drawing on:

- Regulatory precedent, and
- Beta estimates for other utility companies in Central and Latin America.

There are two key issues to resolve prior to the estimation of our comparators' beta values. These are:

- The appropriate time-frame over which to estimate the betas; and,
- The method of de-leveraging our observed equity betas to derive comparable asset betas.

We discuss these two issues below.

*The Appropriate Estimation Time-Frame*

Broadly, there are two alternatives:

- Long-term historic betas, for example, estimated over a five-year period. Estimating betas over a long timeframe would capture the market's historic assessment of risk over the entire business cycle.
- Betas estimated over the most recent period, for example, the most recent year. This will capture the market's perspective on more recent risk exposures.

There is a trade-off between these two approaches. Five-year estimates are more likely to give regression results with lower standard errors, i.e. more "robust" estimates. On the other hand, they present a more dated picture of the risk exposure of the particular company, and therefore less pertinent to future risks.

In estimating our comparators' betas, we think it is important to use current data in estimating betas, which reflects the most up-to-date market view about all factors that impact upon beta values, such as the regulatory environment, supply imbalances, macroeconomic factors, as well as competitive conditions in the operators market. Thus, our preferred position is to estimate betas for the most immediate time period of one year (although we also estimate betas over 2 and 5 year time periods as a cross check).

We use weekly observations in our regression analysis. This provides sufficient data points to derive robust beta estimates. The use of monthly data observations provides too few observations for a regression period of one/two years. We do not present daily data because of concerns about distortions that may occur due to significant time differences between the domestic stock markets for our comparators and other markets.

*Estimating Asset Beta from Equity Beta*

A company's beta is a function of the business risk particular to the company and the extent to which these risks are magnified by the financial leverage decisions of the company. We are interested in estimating our comparators' *asset* betas, which capture only the business and cost risks associated with each company, to the exclusion of financial risk. An asset beta is a beta with assumed zero debt. On this basis, we can then compare betas across companies.

To estimate the cost of equity we then have to "re-gear" the asset beta to accord with BEL's expected capital structure.

The formula we use which relates the equity and asset beta (the leveraging formula) is:

$$\beta_{equity} = \beta_{asset}\,(1+D/E)$$

The remainder of this section is structured as follows:

- Section A.2.2.1 looks at regulatory precedent
- Section A.2.2.2 presents some comparator beta estimates
- Section A.2.2.3 draws conclusions on NERA's best estimate of BEL's beta

### A.2.2.1. Regulatory precedent

Table A.5 shows some regulatory decisions on asset betas in the electricity sector. The values are within the range of 0.31 to 0.56. The average estimate is 0.43-0.44.

Table A.5
Allowed Asset Betas for Electricity Companies

| | Transmission | Distribution |
|---|---|---|
| **United Kingdom** | | |
| Offer / NGC (1997) | 0.56[1] | |
| Ofgem / NGC (2001) | 0.4[1] | |
| Offer / NIE (1997) | 0.55[1] | |
| Ofgem / PESs (2000) | | 0.50[1] |
| Ofgem / DNOs (2004) | 0.35 | |
| **Australia** | | |
| IPART / TransGrid (June 1999) | 0.40[1] | |
| ACCC / TransGrid (January 2000) | 0.47[1] | |
| ACCC / EnergyAustralia (January 2000) | 0.47[1] | |
| ACCC / SMHEA (February 2001) | 0.44[1] | |
| IPART / Electricity distribution (June 1999) | | 0.40[1] |
| IPART / Electricity distribution networks (December 1999) | | 0.35[1] |
| ORG / Victorian electricity distributors (September 2000) | | 0.40 |
| **Italy** | | |
| L'Autorità per l'Energia Elettrica e il Gas (1999) | 0.31[1] | 0.54[1] |
| **Netherlands** | | |
| Dienst uitvoering en Toezicht Energie (2001), up to 2004 | 0.4 | 0.4 |
| **Average** | **0.44** | **0.43** |

*(1) Derived from final rate of return decision by the regulator.*

### A.2.2.2. Comparator beta estimate

There are 135 quoted Central and Latin American utility companies. Only a small number of those are water or gas companies, the rest are either electricity integrated entities or are electricity transmission, distribution or generation companies. Most of them are located in Brazil but there are some also in Argentina, Chile, Peru, Colombia and Venezuela.

Appendix C provides more details about these comparators. Table A.6 presents our beta estimates for integrated electricity companies. It shows that the average 1-year estimate is 0.84 and the average 2-year estimate is 0.65. These are a little higher than the regulatory precedents presented above.

**Table A.6**
**Comparator Beta Estimates**
**(Integrated Electricity Companies)**

| Company Name | Sector | 1Y asset beta | 2Y asset beta | 5Y asset beta |
|---|---|---|---|---|
| **Brazil** | | | | |
| Ampla Energia e Servicos SA | Electric-Integrated | 0.54 | 0.59 | N/A |
| Centrais Eletricas de Santa Catarina SA | Electric-Integrated | 0.86 | 0.78 | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.06 | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.12 | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 0.35 | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.12 | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 1.10 | N/A | N/A |
| Cia Energetica do Ceara | Electric-Integrated | 0.76 | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 1.19 | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 1.38 | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 0.99 | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.09 | 1.00 | N/A |
| Light Servicos de Eletricidade SA | Electric-Integrated | 0.44 | 0.42 | N/A |
| Cia Energetica de Minas Gerais | Electric-Integrated | 0.87 | 0.76 | N/A |
| **Chile** | | | | |
| Colbun SA | Electric-Integrated | 0.80 | 0.72 | N/A |
| Gener SA | Electric-Integrated | 0.39 | 0.46 | N/A |
| Enersis SA/Chile | Electric-Integrated | 0.53 | 0.54 | N/A |
| Empresa Nacional de Electricidad SA/Chile | Electric-Integrated | 0.58 | 0.56 | N/A |
| Average | | **0.84** | **0.65** | |

However, there are a number of reasons why estimates obtained from comparator companies do not form the primary basis for our estimate of BEL's beta. In particular, these include the following:

- Conditions in which companies operate in Central and Latin America are very diverse and make finding appropriate comparators for BEL very difficult.

- We have also encountered significant data issues. For example, out of the 135 potential comparators we have not been able to produce a single five-year beta estimate due to gaps in price data. The number of two-year estimates is significantly smaller than the number of one-year estimates. This reduces our ability to cross-check the more recent estimates against long term values. When using comparator beta estimates this cross-check is very important as comparators may be subject to market changes in the short term that do not affect BEL and hence should not be incorporated in BEL's asset beta. These short term effects are illustrated in the table above where an average one-year integrated comparator beta estimate is almost 0.2 higher than the average 2-year comparator estimate.

### A.2.2.3. Conclusions on NERA's Estimate of BEL's Beta

The evidence examined suggests the following:

- Regulatory precedent suggest a beta in the range of 0.31 to 0.56 with an average estimate of about 0.44
- Integrated companies comparator estimates suggest a range of 0.35 to 1.1. However these are very unreliable:
  - Companies are operating in very different environments, which are not directly relevant to BEL;
  - Data availability means that a longer term estimate cannot be produced to cross-check the more recent estimates.

Given problems with the data we place more value on evidence from the regulatory precedents. We therefore conclude BEL's asset beta is 0.4, which is consistent with the more recent regulatory precedents such as Ofgem's 2004 decision for UK electricity distribution companies and is towards the bottom of the range indicated by comparator companies' betas.

### A.2.3. Equity Risk Premium

The equity risk premium (ERP) is the difference between the expected return on the market portfolio and the expected return on a risk free asset, (formally stated as $E[r_m] - E[r_f]$).

Consistent with prevailing views amongst both academics and finance practitioners, NERA's *approach to estimating the ERP relies primarily on the results obtained from the analysis of* the average difference over the long term between realised returns on the market portfolio, and those on a risk free asset (the so-called *ex post* approach).

The arithmetic mean approach is consistent with the hypothesis that financial markets are efficient, with equity returns serially independent. We believe this is consistent with the majority academic viewpoint and current evidence regarding the efficiency of equity markets.

*Ex-post Approach*

The ex-post approach calculates the average differences between realised (i.e. historical) returns on (a proxy for) the market portfolio and realised returns on (a proxy for) the risk free asset. This presumes that the expected ERP is constant over time and that realised premiums converge towards this expectation when averaged over sufficiently long periods (i.e. there is no systematic bias between expectations and outturns).

There is no correct time period to use when analysing historic data to estimate the ERP. Using long-term historic averages is most likely to overcome the possibility of systematic bias between expectations and outturns. Long-term averages of returns are most appropriate if it is assumed that the equity risk premium is constant over the measurement period and will remain constant in the future.

NERA prefers the use of long-term historic average estimates of the ERP on this basis. Table A.7 presents estimates of very long-run (1900-2000) estimates of the ERP for a selection of countries. The ERP is a function of investor preferences and the standard deviation of the market portfolio. Assuming that investors' risk preferences are relatively consistent across countries, well-diversified markets outside of our Belize reference market are also relevant in determining the ERP.

Consistent with our assumption regarding appropriate reference market, we show ERP in highly diversified markets (the US and the UK) and give a world average estimate. The highly diversified markets ERP's lie in the range of 6.5% to 5.6% (UK) and 7.5% to 6.9% (US), in line with a world average of 7.5% to 6.7%.

However, there is an important issue of consistency here. Our preferred risk-free rate measure is a bond proxy. Therefore, we should also look at historic ERP's measured with respect to bonds. The world average ERP relative to bonds over the period 1990-2000 is shown in Table A.7 as 6.7%.

**Table A.7**
**Long Run Ex Post Equity Risk Premia**

| | ERP relative to Bills | | ERP relative to Bonds | |
|---|---|---|---|---|
| | **Arithmetic** | **Std. dev.** | **Arithmetic** | **Std. dev.** |
| **Highly diversified markets** | | | | |
| UK | 6.5% | 19.9% | 5.6% | 16.7% |
| USA | 7.5% | 19.8% | 6.9% | 19.9% |
| **World average[1]** | **7.5%** | **N/a** | **6.7%** | **N/a** |

*Source: LBS / ABN AMRO (2001) "Millennium Book II, 101 years of investment returns". The estimates are based on 100 years of data, with 1922/3 excluded for Germany where hyperinflation had a major impact on the risk premia and bills returned. (1) The countries included in this average are: Australia, Belgium, Canada, Denmark (from 1915), France, Germany, Ireland, Italy, Japan, Netherlands, Spain, Sweden, Switzerland (from 1911), UK and USA.*

In conclusion, these long run data suggest an ERP of 6.7% in relation to a bond measured ERP.

*Regulatory Precedents on the Equity Risk Premium*

Table A.8 presents recent UK and Irish regulatory precedents on the equity risk premium.

**Table A.8**
**UK and Irish Regulatory Precedent on the Equity Risk Premium**

| Regulator | Case (date) | ERP |
|---|---|---|
| MMC | Cellnet / Vodafone (1998) | 3.5%-5% |
| Ofwat | PR1999 (1999) | 3.0%-4.0% |
| Ofgem | PES (1999) | 3.5% |
| Ofgem | NGC (2000) | 3.5% |
| ORR | Railtrack (2000) | 4.0% |
| CAA | NATS (2000) | 3.5%-5% |
| Competition Commission | Mid-Kent Water Plc; and Sutton and East Surrey Water Plc, (2000) | 4.0% |
| Ofgem | Transco (2001) | 3.5% |
| Oftel | BT (2001) | 5% |
| Competition Commission | BAA (2002) | 2.5%-4.5% |
| Competition Commission | Vodafone, $O_2$, Orange and T-Mobile (2003) | 2.5%-4.5% |
| Ofgem | Final Proposals for DNOs (2004) | 2.5%-4.5% |
| Ofwat | Final Determinations (2004) | ~5.0% |
| Ofcom | Various (2004) e.g Partial Private Circuits charge control, TV licence renewal, mobile termination charges | 5.0% |

*(1) ODTR did not publish the individual components of the cost of capital allowed for Eircom, however we understand that they used the upper bound of parameters recommended by NERA in our report (2002) "Eircom's Cost of capital: A Report for ODTR". We therefore present the risk-free rate recommended in this report.*

UK regulatory precedent shows lower ERPs than those allowed by Irish regulators, ranging between 2.5% and 5.0%. More recent decisions have tended to the upper end of this range. In most cases, some consideration has been given to evidence on historic average returns, however UK authorities have generally judged that the historic ERP overstates the current risk premium. Estimates of the ERP have generally relied heavily on small sample survey evidence on the expectations of investors. Surveys that have been considered by the authorities include CLSE (1999), Price Waterhouse (1998), NERA (1998) and other evidence from investment bank analysts. The reliance on survey evidence has prevailed despite the CC itself recognising that *"this evidence may be subject to biases that are difficult to quantify and assess"* (Competition Commission, 2000a, paragraph 8.28). However, more recently, justification for the ERP allowed by regulators has focused more on a range of evidence including long run historical evidence of equity returns, ex-ante evidence (price-earnings) in addition to survey evidence. This move away from the reliance on survey evidence, which has been subject to a number of criticisms, has paralleled recent increases in the ERP allowed by UK regulators.

The ERP allowed by Irish regulators in recent years has ranged between 5.0% and 7.0%. The ODTR has allowed an ERP at the upper end of this range whilst the CER decisions have tended to be grouped around the lower end of this range. In most cases justification for the ERPs allowed by the CER and ODTR are not explicitly set out. However documentation underlying the ODTR decision prepared by NERA estimates the ERP on the basis of long term historical evidence of equity returns in Eurozone, US and UK markets. The CER state that they base their allowed ERP in the Best New Entrant 2002 decision primarily on ex-post and price-earnings analysis, consistent with regulatory precedent and backed up by ex-ante expectations.

Outside the UK, in countries including the US, Australia and the Netherlands, the ERP has generally been set at a higher level. In the US, although the CAPM is not widely used to estimate the cost of equity, it is often used as a check on the DCF results. The most widely quoted source used in US hearings to assess the level of the ERP is the Ibbotson data.[19] The method recommended by Ibbotson is to compute the arithmetic average of stock market returns against long-term Treasury bond yields.

Table A.9 presents a summary of recent US decisions on the ERP.

**Table A.9**
**Recent US Decisions on the Equity Risk Premium**

| Institution | Case | ERP | Comments on Decision |
|---|---|---|---|
| Connecticut Department of Public Utility Control | Southern Connecticut Gas Company, 2000 | 6.13% | Used a Risk Premium Method to check DCF. The ERP is the arithmetic average from 1974-1998. |
| Connecticut Department of Public Utility Control | Connecticut Power & Light Company, 1999 | 6.52%, 5.89% | Different witnesses performed the CAPM calculation with different ERPs. These submissions were approved by the Commission. |
| Maine Public Utilities Commission | Central Maine Power Company, 1999 | 7.40% - 8.90% | The Commission uses CAPM analysis as a check on the DCF method, and employs this range of ERPs, based on witnesses' recommendations. |
| Public Service Commission of Utah | Pacificorp, dba Utah Power and Light, 1999 | 7.8% | CAPM used as check to DCF model. |
| Public Utility Commission of Oregon | Northwest Natural Gas, 1999 | 8.5% | Commission chose this ERP for use in CAPM. |

*Source: Public Utility Commission Dockets, US State Regulators.*

In Australia, recent regulatory cases have concluded that the market risk premium is most likely to lie in the range of 5.0% to 7.0%. The most recent regulatory decision by the Australian Competition and Consumer Commission (ACCC) used an ERP of 6% for the Victorian transmission network revenue caps for 2003-2008.[20]

In the Netherlands, the electricity regulator DTe published its guidelines for price cap regulation in the period from 2000 to 2003 whereby it "*considers it reasonable to fix the*

[19] Ibbotson Associates publish data on the ERP every year in a handbook, "Stocks, Bonds, Bills & Inflation".

[20] ACCC (2002b), p.27.

*market risk premium between 4% and 7%"*[21]. This range was derived on the basis of the available data and responses from the sector.

*Summary and Conclusions on the Equity Risk Premium*

We summarise evidence presented in this section:

- UK and Irish regulatory precedent shows central estimates of the ERP in the range of 3.5% to 7.0%.
- International regulatory precedent shows central estimates of the ERP of around 7%.

We consider the LBS/ABN AMRO data on the historical equity risk premia over 1900-2000 to be the most compelling and appropriate. This data source is widely recognised as the most comprehensive and consistent dataset of historical returns. It also produces estimates of the ERP that are remarkably consistent across countries over a long period of time. However, we consider that other evidence is consistent with the lower end of this range: Irish and international regulatory precedent supports a range of 5.0% to 7.0%, whilst UK regulatory precedent supports a lower range of 3.5% to 5.0%. Other sources of academic evidence support a range of 4% to 8%, whilst the widely quoted Ibbotsen and Chen (2001) study estimates an equity risk premium in the range of 4% to 6%.

We conclude that 6.7%, LBS/ABN AMRO World average estimate, indicated by the Dimson, Marsh and Staunton analysis is the appropriate ERP for our Belize reference market, taking into account regulatory precedent and other evidence.

### A.2.4. Conclusions on CAPM parameters

Table A.10 summarises our CAPM parameter estimates.

**Table A.10**
**Cost of Equity Parameters**

| Parameter | Estimate |
|---|---|
| Nominal US$ Risk Free Rate | 9.30% |
| Nominal Risk Free Rate (Belizean dollars) | 9.20% |
| Equity Risk Premium | 6.7% |
| Asset Beta | 0.40 |
| Currency Risk Premium | (-0.1%) |

## A.3. Debt Costs and Gearing

The cost of debt can be expressed as the sum of the risk free rate and the company specific debt premium. The company specific debt premium is driven by the ratings that specialist credit rating agencies, such as Standard & Poor's (S&P's), assign to that company, which in turn is explained by analysis of its financial position going-forward.

21 DTE (2000) "Guidelines for price cap regulation of the Dutch electricity sector in the period from 2000 to 2003", February 2000.

Best practice methodology is to estimating the cost of debt and gearing by looking at current evidence on gearing and debt costs reflecting BEL's current position and its prospective gearing and debt costs over the forthcoming regulatory period.

The company specific debt premium is driven by several factors, most notably credit ratings based on financial characteristics such as market capitalisation, earnings, volatility and business risk. As a company's gearing increases the debt premium will tend to increase as a reflection of the increased financial riskiness of the company, i.e. that more cash flow needs to be generated from operations and investments in order to meet interest payments.

### A.3.1. Debt costs

A best practice approach to estimating BEL's cost of debt would be to examine yields to maturity on BEL's trade debt as these represent the most up to date market's assessment of BEL's debt risks. However, BEL has no traded debt. The next best approach would be to examine traded debt costs of other companies with the same credit rating as BEL. Unfortunately, BEL has no credit rating and this alternative assessment is also not possible.

The last alternative is to examine actual BEL's debt costs as well as forward-looking debt cost estimates and use those to come up with an assessment of likely costs if BEL were to raise additional debt finance over the forthcoming regulatory period.

We have examined BEL's actual current debt costs. We have also examined BEL's assessment of future debt costs, including quotes for new loans. Table A.11 below provides a summary of BEL's long term debt position going forward over the 2005-2009 time period.

Based on this evidence we conclude that BEL's weighted average cost of debt over 2005-2009 is 8.76%.[22]

[22] Weighted by each loan's annual opening balance as a proportion of total long-term debt (opening balance) for that year and then averaged over 2005-2009.

## Table A.11
## BEL's Long Term Debt Forecast (US$)

| LONG TERM DEBT | Interest Rate | 2005 $ | 2006 $ | 2007 $ | 2008 $ | 2009 $ | Average (%) |
|---|---|---|---|---|---|---|---|
| **Caterpillar Financial Services** | 5.750% | | | | | | |
| Opening Balance | | 57,327 | - | - | - | - | |
| Weighting[1] | | 0.05 | | | | | |
| **EXIM Bank USA Power III – AllFirst Bank/M&T Bank** | 4.950% | | | | | | |
| Opening Balance | | 3,883,481 | 1,937,444 | - | - | - | |
| Weighting | | 3.60 | 1.72 | | | | |
| **Power II – IBRD/3776** | 7.960% | | | | | | |
| Opening Balance | | 13,012,457 | 11,086,409 | 9,160,361 | 7,234,313 | 5,308,265 | |
| Weighting | | 12.07 | 9.86 | 7.86 | 6.28 | 4.69 | |
| **Power I – CDB/37SFR** | 8.500% | | | | | | |
| Opening Balance | | 1,230,811 | 820,535 | 410,259 | - | - | |
| Weighting | | 1.14 | 0.73 | 0.35 | | | |
| **Power II – CDB/14OR** | 5.500% | | | | | | |
| Opening Balance | | 18,215,302 | 16,509,002 | 14,802,702 | 13,096,402 | 11,390,102 | |
| Weighting | | 16.90 | 14.69 | 12.70 | 11.36 | 10.07 | |
| **Power II – EIB** | 5.000% | | | | | | |
| Opening Balance | | 6,661,919 | 6,209,959 | 5,748,789 | 5,278,410 | 4,808,031 | |
| Weighting | | 6.18 | 5.52 | 4.93 | 4.58 | 4.25 | |
| **Bank of Nova Scotia** | 6.750% | | | | | | |
| Opening Balance | | 2,012,465 | 762,465 | - | - | - | |
| Weighting | | 1.87 | 0.68 | | | | |
| **Gas Turbine Project Financing – RBTT Merchant Bank** | 6.782% | | | | | | |
| Opening Balance | | 22,604,535 | 18,914,831 | 15,225,127 | 11,535,423 | 7,845,719 | |
| Weighting | | 20.97 | 16.83 | 13.06 | 10.00 | 6.94 | |
| **BECOL Loan – Transmission Line** | 10.000% | | | | | | |
| Opening Balance | | 23,321,933 | 20,795,990 | 18,005,548 | 14,922,911 | 11,517,481 | |
| Weighting | | 21.64 | 18.50 | 15.45 | 12.95 | 10.19 | |
| **NEW LOANS (Power IV) (Toronto Dominion)** | 5.750% | | | | | | |
| Opening Balance | | 9,791,015 | 7,607,026 | 5,423,037 | 3,239,048 | 1,055,059 | |
| Weighting | | 9.08 | 6.77 | 4.65 | 2.81 | 0.93 | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **NEW LOANS – First Carribean** | 11.500% | | | | | | |
| Opening Balance | | 7,000,000 | 5,000,000 | 3,000,000 | 1,000,000 | - | |
| Weighting | | 6.49 | 4.45 | 2.57 | 0.87 | | |
| **NEW LOANS (Power V & OTHER PROJ. FIN) – BNS/Others** | 9.00% | | | | | | |
| Opening Balance | | - | 17,456,640 | 39,999,996 | 54,768,746 | 67,506,247 | |
| Weighting | | | 15.53 | 34.32 | 47.51 | 59.70 | |
| **NEW LOANS (BECOL CHALILLO TLINE)** | 10.00% | | | | | | |
| Opening Balance | | - | 5,320,000 | 4,760,000 | 4,200,000 | 3,640,000 | |
| Weighting | | | 4.73 | 4.08 | 3.64 | 3.22 | |
| **DEBENTURE (Series I)** | | | | | | | |
| Opening Balance | 12.00% | 17,014,448 | 17,014,448 | 17,014,448 | 17,014,448 | 17,014,448 | |
| Weighting | | 10.55 | 10.16 | 9.82 | 9.81 | 9.84 | |
| **DEBENTURE (Series II, III,...)** | | | | | | | |
| Opening Balance | 9.492%[2] | 36,047,600 | 37,584,460 | 39,146,847 | 40,724,312 | 42,317,051 | |
| Weighting | | 22.34 | 22.44 | 22.60 | 23.47 | 24.48 | |
| **OTHER LOCAL SHORT TERM DEBT/LINE OF CREDIT** | | | | | | | |
| Opening Balance | 14.500% | 490,000 | 490,000 | 490,000 | 490,000 | 490,000 | |
| Weighting | | **0.30** | **0.29** | **0.28** | **0.28** | **0.28** | |
| **TOTAL DEBT** | | | | | | | |
| Opening Balance | | 161,343,293 | 167,509,209 | 173,187,114 | 173,504,012 | 172,892,402 | |
| **WEIGHTED INTEREST RATE (%)** | | **8.41** | **8.64** | **8.81** | **8.91** | **9.02** | **8.76%** |

*(1) Weighting is estimated as a proportion of loan opening balance vs. total long term debt opening balance.*
*(2) Average of 9.253% and 9.730%.*

### A.3.2. Gearing

Our best estimate of forward-looking gearing for BEL comes from BEL's financial forecasts supplied to the PUC. From these we have been able to estimate an average gearing level over 2004-2009 of 49% (Debt/Equity).[23]

### A.3.3. Conclusions on the cost of debt finance

Table A.12 summarises our assumptions with regard to calculating BEL's debt costs.

**Table A.12**
**Debt and Gearing Assumptions**

| Parameter | NERA assumption |
|---|---|
| Gearing = D/(D+E) | 49% |
| Debt cost | 8.76% |

[23] Source: "05-09 BusPlan (PUC) FTRPVer 7 (PUCRevisedRSARecovenies) (PUC).xls".

## A.2. Conclusions on NERA's Best Estimate

**Table A.13**
**NERA Estimate of BEL's WACC**
**Central Case Assumptions**

| Parameter | NERA Estimate | BEL (S&W) | NERA Methodology |
|---|---|---|---|
| a. Tax rate | 8% | 8% | BEL's corporate tax rate (average over 2004-2009, source = BEL's financial forecasts for PUC) |
| b. Gearing (D/(D+E)) | 49% | 57% | Average over 2004-2009, source = BEL financial forecasts for PUC |
| c. D/E | 0.96 | 1.33 | = b/(1-b) |
| d. Belize forward-looking inflation rate | 2.80% | 2% | IMF International Economic Outlook, September 2004 |
| e. US forward-looking inflation rate | 2.90% | 2% | Differential in 3-month average yield to maturity on a 30-year non-indexed US bond relative to an equivalent indexed one |
| f. Nominal US risk free rate | 4.70% | 3.5% | 30-year US Treasury 3-months average yield to maturity |
| g. Belize country risk premium | 4.60% | 3.54% | 3-months average yield to maturity of 2 CCC+ rated Argentinean bonds and 1 B rated Venezuelan bond |
| h. Currency risk premium | (-0.1%) | 0% | = d-e |
| i. Belize nominal US$ risk free rate | 9.30% | 7.04% | =f+g |
| j. Belize nominal risk free rate (Bz$) | 9.20% | 7.04% | =h+i |
| k. ERP | 6.70% | 6.3% | World long term average historical ERP |
| l. Asset beta | 0.40 | 0.25 | |
| m. Equity beta | 0.78 | 0.58 | =l*(1+c) |
| n. Nominal US$ post-tax cost of equity | 14.55% | 10.70% | = (m*k)+i |
| o. Nominal US$ pre-tax cost of equity | 15.82% | 11.63% | = n/(1-a) |
| p. Nominal post-tax cost of equity (Bz$) | 14.45% | 10.70% | =(m*k)+(h+i) |
| q. Nominal pre-tax cost of equity (Bz$) | 15.71% | 11.63% | =p/(1-a) |
| f. US risk free rate | 4.70% | 3.5% | |
| h. Currency risk premium | (-0.1%) | 0% | |
| r. BEL Debt Premium | 4.06%[2] | 5.46% | Company bond spread for B- rated utilities |
| s. BEL Nominal US$ cost of debt | 8.76% | 8.96% | =f+r |
| t. BEL Nominal cost of debt (Bz$) | 8.66% | 8.96% | =s+h |
| u. Nominal US$ post-tax WACC | 11.4% | 9.30%+2.9%=12.2%[1] (2.9% = "Business Risk Premium") | =(n*(1-b))+(s*b*(1-a)) |
| **v. Nominal US$ pre-tax WACC** | **12.4%** | **10.11%+2.9%=13.0%** | **=o*(1-b)+s*b** |
| w. Real post-tax US$ WACC | 8.3% | 7.16%+2.9%=10.1%[1] | =((u+1)/(1+d))-1 |
| x. Real pre-tax US$ WACC | 9.0% | 7.95%+2.9%=10.8%[1] | =((v+1)/(1+d))-1 |

*NERA analysis.*
*(1) S&W add an additional risk premium to the overall WACC of 2.9%.*
*(2) Implied debt premium based on the overall cost of debt of 8.76% and the risk free rate of 4.7%.*

# Appendix B. Internal Rate of Return Precedents

## B.2. Introduction

In this section we review cost of capital arrangements and rates employed by water regulators in comparable countries, including Chile, Argentina, Belize and the Philippines. We then summarise this information and include other utilities' rates of returns in Latin America in Section B.7.

## B.3. Chile[24]

The cost of capital for Chilean water and wastewater services subject to price setting is calculated according to the following formula:

$$r = r_f + r_p$$

Where r is the cost of capital, $r_f$ is the average internal rate of return and $r_p$ is the risk premium. The internal rate of return is effectively the risk free rate for Chile. It is calculated by taking yield to maturity on the most traded and stable (over the most recent 24 month time period) Central Bank of Chile indexed Treasury bond in local currency with maturity equal or greater than eight years. The period over which the yield to maturity is calculated is set between 6 and 36 months. The number of months of data used depends on how closely this bond followed its overall trend.

The risk premium for each factor is typically in the range of 3.0-3.5% and is calculated based on two types of risks faced by the company: the size of the company and customer types. The two factors are weighted equally to arrive at an overall risk premium.

This method is fairly easy to administer and concessionaires have access to the methodology prior to bidding so debt costs can be factored into the final bid. However, focusing on such a small number of factors may create gaming opportunities by concessionaires in order to increase their rates of return. More importantly, this approach does not factor in the possibility of unforeseen large-scale investment, which may threaten financial viability of the concession in the long run.

## B.4. Aguas Argentinas

We understand that Section 4.2 *"Adecuada Tasa De Descuento (ATD)"* of Resolution 602/99 sets out the appropriate methodology to be used in estimating the cost of capital for Aguas Argentinas ("the Concessionaire"). This methodology calculates the weighted average cost of capital for Aguas Argentinas, and the ATD is to be calculated as follows:

ATD = CD x (1-T) x (D/(D+PN)) + CCP x (PN/(D+PN))

*where*: CD = Cost of debt

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[24] Source: Ian Alexander (ed.) (2004), "Cost of Capital: A Practical Guide For Infrastructure Regulators", World Bank Institute, 2004.

T = Tax rate
D = Financial debt
PN = Patrimonio Neto
CCP = Cost of equity capital

The main conditions set out in Section 4.2 of the Resolution are:

- The risk free rate is to be estimated using the stripped yield to maturity of the 2023 Argentinean par bond expressed in US dollars;
- Beta is to be estimated based on the weekly average of the unlevered beta estimate of UK water utilities for the last two years (under homogeneous hypothesis for comparison);
- The equity risk premium is to be estimated using historical US data on annual returns for ordinary shares compared with long term US Treasury bonds for the previous 30 years. For such comparison, the more representative indices of the most important capital markets in the US should be used;
- The cost of debt is to be estimated using the stripped yield to maturity of the 2023 Argentinean par bond expressed in US dollars;
- The tax rate is specified as the corporation tax rate;
- The cost of capital is to be estimated on a post tax basis.

## B.5. Belize

Belize Water Services Ltd. rate of return is set in Belize Water and Sewerage Byelaws dated 22 April 2002. The following quotation from these Byelaws outlines the methodology:

> *"The Regulated Rate of Return for the licensee, Belize Water Services Ltd., its successors and assigns, is established at twelve percent (12%) and is inextricably linked to the implementation of the Business Plans approved by the PUC in Review Proceedings. The Regulated Rate of Return is to be achieved over the total life of the licence, being twenty-five (25) years commencing on March 23 2001, and is calculated by the receipt of dividends by the licensee's shareholders and any Residual Value paid or payable to the said licensee's shareholders at the end of the licence period by the Government of Belize."*

## B.6. Manila

Article 1 of the Manila Concession Agreement defines the Appropriate Discount Rate (ADR) to mean:

> *"...the real (i.e. not inflation adjusted) weighted average cost of capital (after taxes payable by the concession business). In determining the Appropriate Discount Rate, the Regulatory Office shall apply conventional and internationally accepted methods, and in particular shall make estimates of the cost of debt in domestic and international markets, the cost of equity for utility businesses in the Philippines and abroad and shall make estimates to*

*reflect country risk, exchange rate risk, and any other project risks. The Regulatory Office, at its sole discretion, may consider the Concessionaire's rate of return, either stated or implied in its bid, in determining the Appropriate Discount Rate."*

In determining the ADR to be applied in the course of any of its determinations, the definition given in the Concession Agreement requires the Regulatory Office to strike a balance between two sets of trade-offs. These are the relative weights to be given to:

- Estimates of the cost of capital in Philippine versus international financial markets; and
- The rate of return either stated or implied in the Concessionaire's original bid versus more recent estimates using up-to-date observations of the returns to debt and equity required by the financial markets. MWC's own estimate of its real, pre-tax WACC, as specified in its financial bid, can be determined as follows:

Estimated cost of debt: 3.1%

Targeted return on equity: 16.3%

Targeted gearing ratio: 80%

Effective tax rate: 30%

At 7% inflation rate assumption made by MWC, this implies a nominal rate of return of 12%.

## B.7. Summary on Precedents

Table B.1 summarises average rates of return applied in a number of Latin American countries and other comparable water precedents.

**Table B.1**
**Summary of Rates of Return Applied in Comparable Countries**

| Country | Sector | Company(s) | Average Rate Applied | Notes |
|---|---|---|---|---|
| Argentina[1] | Electricity | Transener/Transnoa | 10.54% - 13.72% | US$, nominal |
| | **Water** | **Aguas Argentinas** | **12.20% – 12.40%** | **US$, nominal, pre-tax** |
| | Gas | All companies in business | 13.10% | US$, real |
| Uruguay[1] | Electricity | UTE | 9.90% – 11.20% | US$, real |
| Bolivia[1] | Electricity | All companies in business | 10.10% | US$, nominal |
| Brazil[1] | Electricity | Escelsa | 10.10% | R$, real |
| **Chile** | **Water** | **All water and wastewater businesses** | $R = r_f + r_p$ (*) | **Chilean peso** |
| **Belize** | **Water** | **Belize Water Services Ltd** | **12%** | **Real, post-tax cost of equity** |
| **Manila** | **Water** | **MWSS** | **12%** | **Nominal, pre-tax** |

*(1) Source: Martin A. Rodriquez-Pardina and Germán Sember (2004), Table III, Case Study 7: Cost of Capital Determinations in Latin America, A Comparative Study in Ian Alexander (ed.), "Cost of Capital: A Practical Guide For Infrastructure Regulators", World Bank Institute, 2004.*
*(*) R is the cost of capital, $r_f$ is the average internal rate of return and $r_p$ is the risk premium in the range of 3.0-3.5%*

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# Appendix C. Comparator Beta Estimates

**Table C.1**
**Comparator Beta Estimates**

| Company Name | Sector | 1Y asset beta | 2Y asset beta | 5Y asset beta |
|---|---|---|---|---|
| **Argentina** | | | | |
| Cia de Transporte de Energia Electrica de Alta Tension SA | Electric-Transmission | N/A | N/A | N/A |
| Central Costanera SA | Electric-Generation | N/A | N/A | N/A |
| Camuzzi Gas Pampeana SA | Gas-Distribution | N/A | N/A | N/A |
| MetroGas SA | Gas-Distribution | N/A | N/A | N/A |
| Cia de Transporte de Energia Electrica de Alta Tension SA | Electric-Transmission | 0.17 | 0.21 | N/A |
| Distribuidora de Gas Cuyana SA | Gas-Distribution | N/A | N/A | N/A |
| Central Puerto SA | Electric-Integrated | N/A | N/A | N/A |
| Gas Natural BAN (Argentina) | Gas-Distribution | 0.34 | 0.44 | N/A |
| Central Costanera SA | Electric-Generation | 0.42 | 0.44 | N/A |
| MetroGas SA | Gas-Distribution | N/A | N/A | N/A |
| Capex SA | Electric-Integrated | N/A | N/A | N/A |
| MetroGas SA | Gas-Distribution | N/A | N/A | N/A |
| Capex SA | Electric-Integrated | N/A | N/A | N/A |
| **Brazil** | | | | |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | N/A | N/A | N/A |
| Cia de Gas de Sao Paulo | Gas-Distribution | N/A | N/A | N/A |
| Cia Energetica do Maranhao | Electric-Integrated | N/A | N/A | N/A |
| Inepar Energia SA | Electric-Integrated | N/A | N/A | N/A |
| Inepar Energia SA | Electric-Integrated | N/A | N/A | N/A |
| Ampla Energia e Servicos SA | Electric-Integrated | 0.54 | 0.59 | N/A |
| Rio Grande Energia SA | Electric-Distribution | N/A | N/A | N/A |
| Centrais Eletricas de Santa Catarina SA | Electric-Integrated | N/A | N/A | N/A |
| Centrais Eletricas de Santa Catarina SA | Electric-Integrated | 0.86 | 0.78 | N/A |
| Centrais Eletricas Matogrossenses SA | Electric-Integrated | N/A | N/A | N/A |
| Centrais Eletricas Matogrossenses SA | Electric-Integrated | N/A | N/A | N/A |
| Cia Forca e Luz Cataguazes - Leopoldina | Electric-Integrated | N/A | N/A | N/A |
| Cia Forca e Luz Cataguazes - Leopoldina | Electric-Integrated | N/A | N/A | N/A |
| Cia Energetica de Sao Paulo | Electric-Generation | N/A | N/A | N/A |
| Cia Forca e Luz Cataguazes - Leopoldina | Electric-Integrated | N/A | N/A | N/A |
| Caiua Servicos de Eletricidade | Electric-Integrated | N/A | N/A | N/A |
| Caiua Servicos de Eletricidade | Electric-Integrated | N/A | N/A | N/A |
| Cia de Saneamento do Parana | Water | 0.77 | N/A | N/A |
| Centrais Eletricas do Para SA | Electric-Distribution | N/A | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | N/A | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.06 | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.12 | N/A | N/A |
| Cia Energetica do Ceara | Electric-Integrated | N/A | N/A | N/A |
| Centrais Eletricas do Para SA | Electric-Distribution | N/A | N/A | N/A |

| | | | | |
|---|---|---|---|---|
| Cia Energetica do Maranhao | Electric-Integrated | N/A | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 0.35 | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.12 | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 1.10 | N/A | N/A |
| Cia Energetica do Ceara | Electric-Integrated | 0.76 | N/A | N/A |
| Empresa Metropolitana de Aguas e Energia SA | Electric-Generation | 0.70 | N/A | N/A |
| Cia Estadual de Energia Eletrica do Rio Grande do Sul | Electric-Integrated | N/A | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 1.19 | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | 1.38 | N/A | N/A |
| Cia Energetica de Brasilia | Electric-Integrated | N/A | N/A | N/A |
| Elektro Eletricidade e Servicos SA | Electric-Distribution | N/A | N/A | N/A |
| CPFL Geracao de Energia SA | Electric-Distribution | N/A | N/A | N/A |
| Cia Energetica de Sao Paulo | Electric-Generation | 0.75 | N/A | N/A |
| CPFL Geracao de Energia SA | Electric-Distribution | N/A | N/A | N/A |
| Tractebel Energia SA | Electric-Generation | N/A | N/A | N/A |
| Cia Energetica de Pernambuco | Electric-Integrated | N/A | N/A | N/A |
| Tractebel Energia SA | Electric-Generation | 0.52 | N/A | N/A |
| Cia Energetica de Sao Paulo | Electric-Generation | 1.19 | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 0.99 | N/A | N/A |
| Empresa Energetica de Mato Grosso do Sul SA | Electric-Integrated | N/A | N/A | N/A |
| Duke Energy International Geracao Paranapanema SA | Electric-Generation | N/A | N/A | N/A |
| Cia de Saneamento Basico do Estado de Sao Paulo | Water | N/A | N/A | N/A |
| Cia Energetica de Pernambuco | Electric-Integrated | N/A | N/A | N/A |
| Tractebel Energia SA | Electric-Generation | 0.47 | 0.46 | N/A |
| Empresa Energetica de Mato Grosso do Sul SA | Electric-Integrated | N/A | N/A | N/A |
| Cia Paranaense de Energia | Electric-Integrated | 1.09 | 1.00 | N/A |
| Cia Paranaense de Energia | Electric-Integrated | N/A | N/A | N/A |
| Duke Energy International Geracao Paranapanema SA | Electric-Generation | N/A | N/A | N/A |
| Cia Energetica de Brasilia | Electric-Integrated | N/A | N/A | N/A |
| Cia de Saneamento Basico do Estado de Sao Paulo | Water | 1.09 | 1.02 | N/A |
| Cia Piratininga de Forca e Luz | Electric-Integrated | N/A | N/A | N/A |
| Empresa Bandeirante de Energia SA | Electric-Distribution | N/A | N/A | N/A |
| CPFL Energia SA | Electric-Integrated | N/A | N/A | N/A |
| Cia Distribuidora de Gas do Rio de Janeiro | Gas-Distribution | N/A | N/A | N/A |
| CPFL Energia SA | Electric-Integrated | N/A | N/A | N/A |
| Tractebel Energia SA | Electric-Generation | N/A | N/A | N/A |
| Cia Energetica de Minas Gerais | Electric-Integrated | N/A | N/A | N/A |
| Cia de Transmissao de Energia Eletrica Paulista | Electric-Transmission | N/A | N/A | N/A |
| Cia Energetica de Minas Gerais | Electric-Integrated | N/A | N/A | N/A |
| CPFL Energia SA | Electric-Integrated | N/A | N/A | N/A |
| Cia Energetica de Minas Gerais | Electric-Integrated | N/A | N/A | N/A |
| Cia de Transmissao de Energia Eletrica Paulista | Electric-Transmission | N/A | N/A | N/A |
| Tractebel Energia SA | Electric-Generation | N/A | N/A | N/A |
| Cia Energetica de Minas Gerais | Electric-Integrated | N/A | N/A | N/A |

| | | | | |
|---|---|---|---|---|
| Centrais Eletricas Brasileiras SA | Electric-Integrated | N/A | N/A | N/A |
| Centrais Eletricas Brasileiras SA | Electric-Integrated | N/A | N/A | N/A |
| Eletropaulo Metropolitana de Sao Paulo SA | Electric-Distribution | N/A | N/A | N/A |
| AES Tiete SA | Electric-Generation | N/A | N/A | N/A |
| AES Tiete SA | Electric-Generation | N/A | N/A | N/A |
| Cia Energetica de Minas Gerais | Electric-Integrated | N/A | N/A | N/A |
| Light Servicos de Eletricidade SA | Electric-Integrated | 0.44 | 0.42 | N/A |
| Cia Energetica de Minas Gerais | Electric-Integrated | 0.87 | 0.76 | N/A |
| Eletropaulo Metropolitana de Sao Paulo SA | Electric-Distribution | N/A | N/A | N/A |
| Espirito Santo Centrais Eletricas SA | Electric-Integrated | N/A | N/A | N/A |
| Cia Paulista de Forca e Luz | Electric-Distribution | N/A | N/A | N/A |
| Cia Paulista de Forca e Luz | Electric-Distribution | N/A | N/A | N/A |
| Cia Paulista de Forca e Luz | Electric-Distribution | N/A | N/A | N/A |
| Cia de Eletricidade do Estado da Bahia | Electric-Integrated | N/A | N/A | N/A |
| Cia de Saneamento Basico do Estado de Sao Paulo | Water | 0.42 | 0.40 | N/A |
| Cia de Gas de Sao Paulo | Gas-Distribution | N/A | N/A | N/A |
| Cia de Gas de Sao Paulo | Gas-Distribution | 0.68 | 0.80 | N/A |
| Aes Sul Distribuidora Gaucha de Energia SA | Electric-Distribution | N/A | N/A | N/A |
| Aes Sul Distribuidora Gaucha de Energia SA | Electric-Distribution | N/A | N/A | N/A |
| **Chile** | | | | |
| Enersis SA/Chile | Electric-Integrated | N/A | N/A | N/A |
| Enersis SA/Chile | Electric-Integrated | N/A | N/A | N/A |
| Enersis SA/Chile | Electric-Integrated | N/A | N/A | N/A |
| Empresa Nacional de Electricidad SA/Chile | Electric-Integrated | N/A | N/A | N/A |
| Empresa Nacional de Electricidad SA/Chile | Electric-Integrated | N/A | N/A | N/A |
| Empresa Nacional de Electricidad SA/Chile | Electric-Integrated | N/A | N/A | N/A |
| Almendral SA | Electric-Integrated | N/A | N/A | N/A |
| Colbun SA | Electric-Integrated | 0.80 | 0.72 | N/A |
| Empresa Obras Sanitar Valpar | Water | N/A | N/A | N/A |
| Empresa Electrica Arica | Electric-Integrated | N/A | N/A | N/A |
| Gener SA | Electric-Integrated | 0.39 | 0.46 | N/A |
| Enersis SA/Chile | Electric-Integrated | 0.53 | 0.54 | N/A |
| Empresa Electrica Iquique | Electric-Integrated | N/A | N/A | N/A |
| Aguas Andinas SA | Water | 0.71 | 0.69 | N/A |
| Empresa Electrica Antofagast | Electric-Integrated | N/A | N/A | N/A |
| Cia Electrica del Rio Maipo | Electric-Distribution | N/A | N/A | N/A |
| Empresa Electrica Pilmaiquen | Electric-Integrated | N/A | N/A | N/A |
| Empresa Electrica del Norte Grande SA/Chile | Electric-Integrated | N/A | N/A | N/A |
| Empresa Nacional de Electricidad SA/Chile | Electric-Integrated | 0.58 | 0.56 | N/A |
| Empresa Electrica Pehuenche SA | Electric-Generation | 0.58 | N/A | N/A |
| Chilectra | Electric-Integrated | N/A | N/A | N/A |
| Cia General de Electricidad | Electric-Distribution | 0.51 | 0.45 | N/A |
| Cia de Consumidores de Gas de Santiago SA | Gas-Distribution | 0.67 | N/A | N/A |

| | | | | |
|---|---|---|---|---|
| Cia Electrica del Litoral SA | Electric-Integrated | N/A | N/A | N/A |
| Empresa Electrica Atacama | Electric-Distribution | N/A | N/A | N/A |
| Empresa Electrica de Magallanes SA | Electric-Integrated | N/A | N/A | N/A |
| **Colombia** | | | | |
| Interconexion Electrica SA | Electric-Transmission | N/A | N/A | N/A |
| Gas Natural ESP | Gas-Distribution | N/A | N/A | N/A |
| **Peru** | | | | |
| Empresa Regional Electronorte Medio Hidrandina SA | Electric-Integrated | N/A | N/A | N/A |
| Edelnor SA/Peru | Electric-Integrated | N/A | N/A | N/A |
| Edegel SA | Electric-Generation | N/A | N/A | N/A |
| Empresa Generacion Termoelectrica Ventanil | Electric-Generation | N/A | N/A | N/A |
| Luz del Sur SAA | Electric-Integrated | N/A | N/A | N/A |
| **Venezuela** | | | | |
| Corp Industrial de Energia C.A. | Electric-Generation | N/A | N/A | N/A |
| Electricidad de Caracas | Electric-Generation | 0.27 | 0.41 | N/A |

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## SCHEDULE 2

(Section 28(4))

**Fuel Surcharge Cost Adjustment**

The Company shall, in addition to the charges set out in Schedule 1 as amended in accordance with this Act, be entitled to add or shall deduct a fuel surcharge per unit consumed which shall be calculated from the following formula:

The total number of Imperial gallons of diesel fuel used at all the Company's generating stations in Saint Lucia during the calendar month immediately preceding the calendar month during which meters are read:

(a) multiplied by the current price less the base price in cents; and

(b) divided by the total units sold in Saint Lucia during the calendar month immediately preceding the calendar month during which meters are read.

## SCHEDULE 3

(Section 29)

## PART A
### ALLOWABLE RATE OF RETURN

Allowable Rate of Return as set out in this Act in respect of each financial year of the Company is computed as the addition of the Weighted Average Percentage Cost of Equity and the Weighted Average Percentage Cost of Debt, where:

Weighting Attributable to Equity x Target Rate of Return = Weighted Average Percentage Cost of Equity; and where

Weighting Attributable to Debt x Average Interest Rate = Weighted Average Percentage Cost of Debt

In such calculation, the Average Amount of Equity and the Average Debt added together form the Total Average Debt and Equity where—

(i) Average Amount of Equity = "i"

Average Debt = "i i"
Total Average Debt and Equity = "iii" = i + ii

and where—

(ii) $\frac{\text{Average Amount of Equity(i)}}{\text{iii}}$ x 100 = % Weighing Attributable to Equity;

and where—

(iii) $\frac{\text{Average Debt(ii) x 100}}{\text{iii}}$ = % Weighing Attributable to Debt

## PART B
### TARGET RATE OF RETURN

The Target Rate of Return is that level of annual rate of return to be attained on the equity of the Company which shall be not less than the average 12 month deposit rate paid by commercial banks in Saint Lucia plus an additional 10% (which shall be 1000 basis points). However, such return on equity shall be at a rate not less than 15% per year (such figure to be expressed to 3 decimal places).

# SCHEDULE 4

(Section 30(1) & 32)

Form of Rate of Return – Interim/Final

Particulars in respect of financial year ended ........................................................................

(All amounts to be expressed in Eastern Caribbean currency and given to nearest dollar.)

A.: <u>Calculation of net income, using amounts derived from the financial statements for the year under review, as follows</u>

| | | | EC$ | EC$ |
|---|---|---|---|---|
| 1) | Revenue in respect of | | | |
| | (a) | Energy sales | 1(a) | |
| | (b) | Revenue derived from or connected with any operating expense or asset included in item 2 below (including, without limitation, increase/decrease in provision for unbilled sales) | 1(b) | |
| | (c) | Fuel surcharge after deducting excess fuel costs over base cost | 1(c) | |
| | | | | 1(a)+1(b)+1(c) =I |
| 2) | Operating Costs in respect of | | | |
| | (a) | Diesel generation | 2(a) | |
| | (b) | Transmission and distribution | 2(b) | |
| | (c) | Consumer services | 2(c) | |
| | (d) | Administrative expenses | 2(d) | |
| | (e) | Directors expenses | 2(e) | |
| | (f) | Maintenance expenses | 2(f) | |
| | (g) | Expenses derived from or connected with any operating income or asset not included in 2(a) to 2(f) above | 2(g) | |
| | (h) | Interest in excess of 15% on moneys borrowed and all interest on consumer deposits | 2(h) | |
| | (i) | Any tax or imposition of any kind imposed by Government or any authority | 2(i) | |
| Sub-total | | | 2(j) | |
| Less: Depreciation charges included in any of 2(a) to (i) above | | | 2(k) | |

| | | | |
|---|---|---|---|
| | | | 2(j)–2(k) = II |
| 3) | Sub-total (being I minus II) | III | |
| 4) | Total depreciation charges calculated on historical cost basis of the Company's fixed assets, less amortization of consumer contributions | IV | |
| 5) | Realised gains or losses incurred on the repayment of foreign currency loan principal | V | |
| 6) | Operating Income (being III minus IV plus or minus V) | VI | |

B. Components of Rate Base

7) Average fixed physical assets and construction work in progress shall be calculated as

(i) Fixed physical assets at book value

(a) at beginning of year
(b) at end of year

Average fixed physical assets (AFPA) is calculated as $\frac{7(i)a + 7(i)b = c}{2}$

and:

(ii) Construction work in progress (WIP) shall be calculated as:
(d) net book value at beginning of year
(e) net book value at end of year

where average WIP is calculated as $\frac{7(ii)d + 7(ii)e = f}{2}$

and where average fixed physical assets is Sum of c+f = VII

8) Allowable Inventory shall be calculated
as the sum of:

(i) Material and stock (excluding fuel) at net book value:

(a) at beginning of year
(b) at end of year

average allowable material and stock inventory is therefore $\frac{8(i)a + 8(i)b = g}{2}$

where g is subject to a maximum of 12.5% of VII;

and:

(ii) The net book value of all fuel (including without limitation lube oil) held by the Company

(c) at the beginning of year

(d) at end of year

where average allowable fuel inventory is calculated as $\frac{8(ii)c + 8(ii)d = h;}{2}$

where h may not exceed 1.5 times the maximum monthly fuel consumption in imperial gallons multiplied by the average price of fuel per imperial gallon;

and where allowable inventory is calculated as Sum of g+h = VIII.

9) Average prepayments and deposits made by the Company shall be calculated at book value:

(a) at beginning of year
(b) at end of year

where average allowable prepayments and deposits is calculated as $\frac{9(a) + 9(b) = j}{2}$

where j may not be greater than 1.5% of AFPA, and which shall = IX

10) Allowable cash working capital shall be calculated as:

(a) Total operating costs (II)

less fuel oil costs

(b) Consumer deposits held as security against non-payment of electricity bills

and where 10(a)x12.5%-10(b) = X

c. Calculation of Rate Base VII+VIII+IX+X = XI

11) Rate Base

d. Calculation of Actual Rate of Return

12) Interim/Final Rate of Return to 3 decimal places VI divided by XI = ___%

I certify to the best of my knowledge these particulars to be correct.

______________________________

*Chairperson or Managing Director or Company Secretary*
*St Lucia Electricity Services Limited*

## GUIDELINES FOR SCHEDULE 4

The following principles shall apply when preparing Interim and Final Returns in accordance with this Schedule:

A) No expense shall be taken into account for the purpose of determining the Interim/Final Rate of Return for any financial year unless such expense has been reasonably and necessarily incurred in producing the operating revenues for the said year.

B) Interest in excess of 15% on moneys borrowed is allowable as an expense, together with all interest paid on consumer deposits.

C) No amortization or goodwill costs will be allowed as expenses in determining operating income.

D) The foregoing shall not be interpreted to exclude charitable donations and similar non-essential expenditures if such do not exceed 2% of the total operating costs defined in this Schedule as "II". Guarantee fees payable in connection with debt obligations arising under agreements entered into on and after the date of the coming into operation of this Act shall be excluded from the calculation of operating expenses.

E) Fixed physical assets shall be valued at historical cost less consumer contributions and less the amount of accumulated depreciation computed at annual rates designed to depreciate fully the said assets on a straight line basis over their respective estimated useful lives.

F) Depreciation provisions shall be in accordance with generally accepted accounting principles and practices as used by the Company for accounting purposes.

G) All expenses incurred in establishing and maintaining a captive insurance fund for the companies benefit. *(Amended by Act 26 of 2001)*

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