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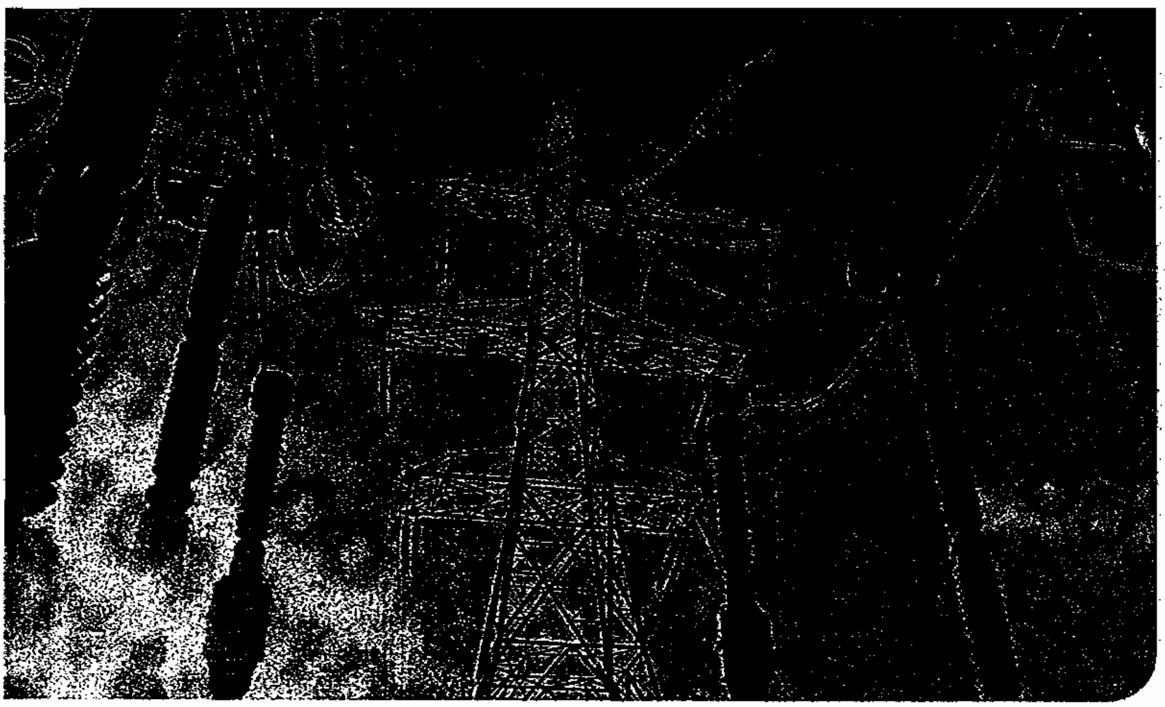
Benchmark Study Report 2002-2006

for

The Barbados Light & Power Company Ltd



Adapted from the Carilec Caribbean Benchmark Study 2006

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1. Executive Summary

1.1 Introduction

The Barbados Light & Power Company Ltd (BLPC) is a participant to the Caribbean Benchmark Study of CARILEC, the Caribbean Electric Utility Services Corporation, who retained the services of KEMA since 2002 to conduct a yearly benchmarking study of its member utilities in order to assess and compare regional performance.

On request of **BLPC** this Benchmark Study Report with benchmarking results of the years 2002 through 2006 has been prepared as a version that is in particular focusing on the performance of BLPC against other Caribbean utilities, which have been kept anonymous in this version.

The CARILEC Benchmark Report 2006 and the database with benchmarking data of the years 2002 through 2006 are the basis for this Benchmark Report as prepared for BLPC.

This Benchmark Report will contain, next to introductions on the backgrounds of the Carilec Benchmark Study, the Benchmarking methodology and the Performance Indicators:

- results of calculated performance indicators presented in graphs and tables
- commentaries on BLPC's performance
- recommendations where appropriate
- a comparison of BLPC's performance against US and European utilities. For this comparison a set of the most relevant financial, technical and organizational performance indicators have been selected
- commentaries on the general performance of island systems as compared to large, interconnected, mainland utility systems. In particular it will be emphasized how this relates to BLPC's operations
- an analysis on 'best practice' in the various dimensions that are included in the benchmark report and on where BLPC stands with regard to this best practice. One can identify best practice among the island utilities and best practice in Europe and the USA.

The purpose of the yearly Carilec Benchmark Reports is to present to CARILEC and the participating utilities like BLPC the progress and evolution of the Caribbean Utilities based on the methodology established in the first report on the year 2002, based on the information sent by seventeen utilities in the questionnaire for this year 2002. Eleven utilities participated in the year 2004, sixteen utilities in 2005 and seventeen utilities sent in the data for the Benchmark Report

2006. For completeness and self supporting, this report presents some of the material of the Carilec report such as methodological aspects, the calculated indicators for the years 2002 through 2006, the comparison with international best practices and the conclusions and recommendations derived from the study, as given to Carilec and the participating utilities.

Based on the data supplied by the utilities and the analysis of the performance indicators calculated, the following are the main findings of the study as reported in the Carilec Benchmark Study Report, followed by the main findings of this special version with special emphasis on BLPC.

1.2 Major Findings

1.2.1 Carilec Report's Major Findings

- All participating utilities are vertically integrated companies which are taking care of power production as well as power transmission, distribution and commercialization. In only one of the participating islands is power production and distribution taken care of by two separate companies.
- The results of the years 2002 through 2006 are quite similar. But major changes are of course obvious in the field of generation costs since fuel prices have gone up in the period from 2002 to 2006.
- The cost structure of the utilities is basically quite similar with fuel costs and operation and maintenance costs as the dominant costs.
- The physical characteristics of the generation, transmission and distribution systems show very little changes between 2002 and 2006. Thermal generation is the predominant source in the region, with many islands, like Barbados, depending on this for 100% of their electricity needs. Transmission and Distribution systems are predominantly aerial with increasing importance of underground facilities due to the constant threat of hurricanes in almost all the islands.
- Differences in performance that have been found can partly be explained by differences in the characteristics beyond the control of utilities like customer base, load density, demand composition, geographical differences.
- Other differences in the indicators point out a more efficient performance of some companies compared to others regarding particular aspects. These differences may indicate opportunities for improvement.
- Some specific findings include the following:
  - The region has a very high coverage of electricity service
  - The regional average for energy losses is comparable to other world regions and energy losses in Barbados can be considered to be among the best in the world

- System load factors are very similar across the region
- The regional average energy cost is high compared with other world regions. This is mainly due to the facts that an island system must keep up a higher reserve margin, does not have the benefit of economies of scale (higher fuel costs, higher equipment costs, more employees per 1,000 customers, and other factors) and is restricted in the fuel options available because of its size.
- Electricity rates are high compared to international figures, which is also an effect of low economies of scale.
- Sufficient generation reserves are found in most of the utilities in the region
- Generation availability is generally high indicating good maintenance practices
- Network and retail costs are reasonable considering system characteristics
- Labor productivity is low compared to international figures, which again has to do with low economies of scale. BLPC has shown however that it can compete on labor productivity with mainland utilities.

• For some important aspects of utility operations like non-technical losses, non-served energy, and service interruptions insufficient information was available to benchmark results.

1.2.2 Major Findings on BLPC's performance within the Caribbean peer group and compared to best practices

- Except for a few performance indicators BLPC is performing as one of the best utilities among its Caribbean peers.
- On issues like T&D costs, system losses, SAIFI, labor productivity, bad debt, BLPC can compete with large mainland utilities. The observation is that on these areas of T&D, BLPC's performance can be compared favourably with international "best practices", while in the remaining areas it is performing at an average level.
- On Generation and Fuel Costs BLPC is performing among the best of the peer group. Apparently the combination of BLPC's production mix, BLPC's extensive use of least costly heavy fuel and BLPC's high labor productivity is resulting in the relatively good performance, while also the trend of cost increase during the years 2002-2006 is more moderate than most of the cost increases as shown by the peer group's utilities. In the field of generation BLPC is part of the "best practices" in its Caribbean peer group, while BLPC – like all island systems – stay behind of mainland systems because of the lack of economies of scale, restrictions in fuel options due to the low scale, and the need for a higher reserves margin because there are on interconnections with other systems. It would be a useful exercise for BLPC to explore the frontiers of excellence, in order to have a better view on where they stand.
- During the years 2002 – 2006 BLPC's tariffs has also shown to be among the lowest in the region.

- Compared with most other utilities as well as with best practices worldwide BLPC's financial performance is behind, which is shown by the relatively low Operational Profit Margin and also a quite low Return on Assets. At the same time BLPC has a relatively low debt level, and relatively many investments are paid directly out of the company's revenues. Looking at these financial parameters and at the relatively low rates this may all together be part of an overall financial and/or business policy at BLPC.

2. Information and Data

This chapter presents the information and data used by the Consultant, KEMA Inc., to measure and benchmark regional operating performance considering technical, economical, financial and organizational aspects of the utilities.

2.1 Selected Set of Indicators

The set of performance indicators selected for this report is the same proposed and adopted in the first report, based on the following criteria:

- Indicators used internationally by electric utilities to measure and monitor the performance of their operations
- Performance indicators tailored to the specific characteristics of island systems of Caribbean utilities
- Aggregate indicators suitable to be used at executive level for management purposes
- Indicators covering the different areas of the utility business considering technical, economical, financial and organizational aspects.
- Indicators for the following functional areas: general operation, generation business, transmission-distribution business and commercial operations.
- Indicators suitable to be used as part of a Performance Monitoring System
- Availability of information required to calculate the indicators

The list and definitions of the performance indicators used in the study are presented in Annex 1.

2.2 Participant Utilities

Seventeen (17) member utilities of CARILEC provided information for the year 2006 study. During the years in total twenty two (22) member utilities have contributed to the Benchmark Study. Most of them throughout the years, like BLPC, some of them only in one or in a few years. Some utilities for example did not participate in a certain year because they were hit severely in that year by a hurricane, which had the effect that there performance indicators could not be considered representative indicators anymore.

2.3 Regional Database

The information and data collected by the Consultant were used to build a Regional Database for Carilec with the characteristics of the electric systems for the year 2006 and the operating results of the utilities for the years 2002, 2004, 2005 and 2006. The Regional Database contains the data used to calculate the performance indicators and other information useful for the benchmarking analysis. All data are on an annual basis.

Since the data of all participants is confidential the database will not be provided as an Appendix to this Report.

2.4 Utility Data

The Consultant used information and data supplied by the participating utilities through a standard questionnaire distributed by CARILEC for that purpose.

The Consultant has made reasonable efforts to check the validity and consistency of the data collected. The information presented in this report is intended for the sole purposes of this study, any error or inaccuracy in the data included here is involuntary and the Consultant does not assume any responsibility for it neither for unintended uses of the results.

3. Benchmarking Analysis

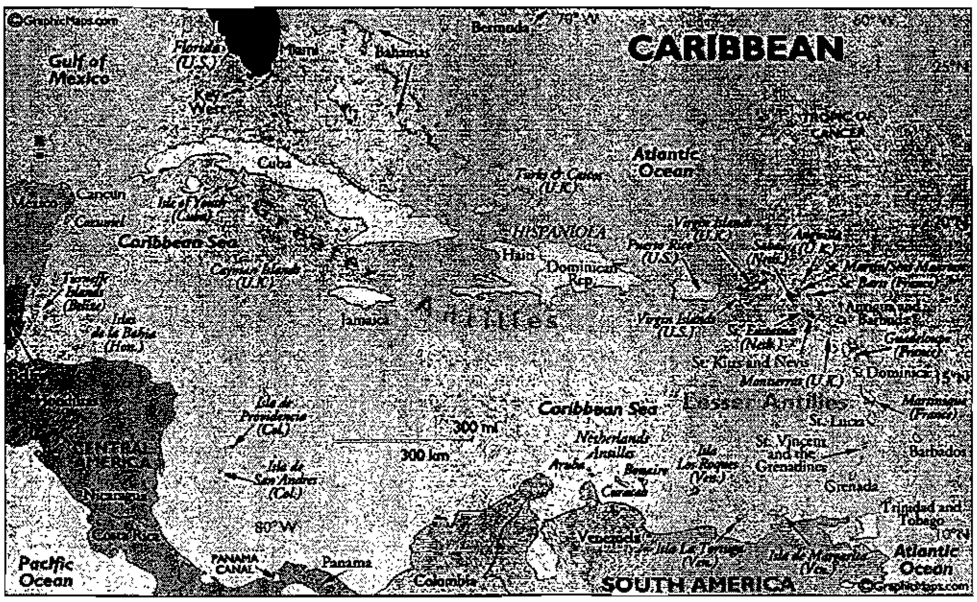
Based on the information collected from the participant utilities, the Consultant calculated the performance indicators of the regional utilities and analyzed several key aspects in order to identify the main characteristics of electricity supply in the Caribbean region and assess the performance profile of the utilities with regard to technical, economical, financial and organizational aspects. Background information, relevant features of electricity service in the region, the performance indicators and the benchmarking analyses are presented in this section.

3.1 Regional Context

3.1.1 General Background

The majority of countries and territories forming the Caribbean region are located in the islands of the Caribbean Sea basin and the total population of approximately 42 million is mostly concentrated in the largest islands. Agriculture, extraction of natural resources, tourism and other services constitute the basis of the islands' economies, with manufacturing being also important in the largest islands.

Figure 1
Caribbean Region



The perspectives of the electricity supply in the region are inseparable to its economic development and the availability of energy resources. The economic activity is the main driver of electricity demand and will determine future requirements in terms of new investments, reliability and quality of service. On the other hand, with a few exceptions, the islands are predominantly net energy importers and oil dependent, so energy costs and environmental awareness will be high in the public policy agenda.

Over the past decade, the Caribbean countries have made major efforts to integrate their economies and coordinate policies. The major regional organization is CARICOM, the Caribbean Community and Common Market, whose objectives are economic cooperation through a common market, coordination of foreign policy and cooperation in common services in several areas. Other main organizations include the Organization of Eastern Caribbean States and the Eastern Caribbean Central Bank. CARILEC is the regional body of the electric utility industry.

3.1.2 Economic Outlook

The whole region is facing significant economic challenges stemming from increased exposure to global competition and the end of trade privileges for many of its traditional products. At the same time, because the region is relatively stronger than other world areas, development assistance is diminishing.

As traditional commodities suffer the effects of economic globalization, there is a growing dependence on the service sector. Many islands are looking to diversify their industrial base counting on tourism and financial services as sources of economic strength, which increase pressure to improve competitiveness for those activities. Economic and reliable electricity supply is considered a key factor to serve these goals.

Other relevant trend is the spread of structural reforms with economic liberalization and privatization becoming increasingly important in the political agenda, with the support of international organizations like the World Bank and the IMF. Like other parts of the world, the Caribbean region is moving along this path with countries implementing reforms at different speeds.

Regional economies show a steady growth keeping pace with the world economy recovery and as a result of structural reforms.

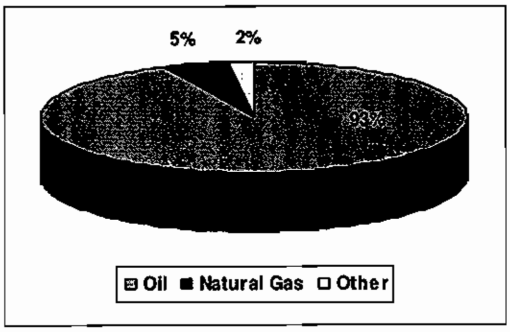
The power sector and electric utilities are strongly affected by a demand that follows economic cycles and by the economic welfare of its customers, especially from tourism, which directly or indirectly supports one out every four jobs in the region. The utilities are also exposed to increased pressure to contribute to economic competitiveness of the islands and from impending regulatory reforms that will bring about changes in the structure of the power sector, the establishment of independent regulatory agencies and increased demands on cost efficiency and service quality.

3.1.3 Energy Policy

With regard to energy resources and utilization, the region keeps facing high oil dependency as illustrated in Figure 2. For the islands this means that the main energy source is costly, subject to price volatility, vulnerable to supply interruptions and not environmentally friendly. Regional energy policies – like the "***National Energy Policy of Barbados***" of which a first draft was issued in December 2006 and the draft "***Caricom Regional Energy Policy***" as issued in early 2007 - are therefore considering energy supply alternatives, incentives for efficient use and increased reliance on market-based solutions to ensure a sustainable development, supporting economic growth and protecting the environment. With respect to electricity, the islands are looking for ways to lower energy costs while improving service performance and reliability.

Despite access to abundant oil and gas resources in countries like Venezuela, Mexico, and Trinidad and Tobago, the energy options for the islands are limited and there is increasing attention for possible fuel diversification options (like conversion from LFO to HFO, looking at the feasibility of for example pet-coke and natural gas) and for renewable energy sources, especially considering the associated environmental benefits. Wind and solar power are the main targets, while possibilities on geothermal energy and bio-fuels have also gained more interest among the Caribbean islands. For areas where geothermal and hydropower can be developed at a large scale, plans are also being developed for supplying islands by submarine cable connections. Wind power projects exist in Curacao, Jamaica, Guadeloupe and Martinique and are being prepared in more islands, like Bonaire, Aruba, Puerto Rico, and the Dominican Republic. The option of wind is also being pursued in Barbados. Furthermore there are more and more solar water heaters and small-scale photovoltaic applications in many islands. In Barbados the solar water heaters are widely used by the majority of the households.

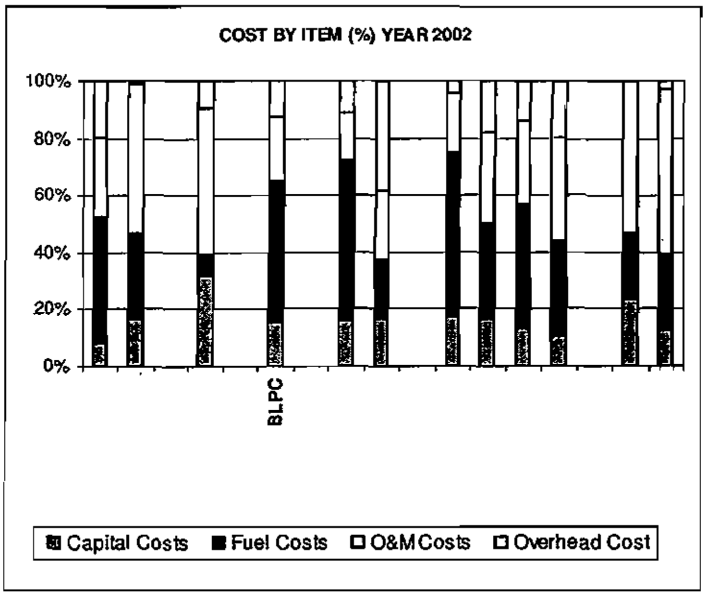
Figure 2
Primary Energy Consumption

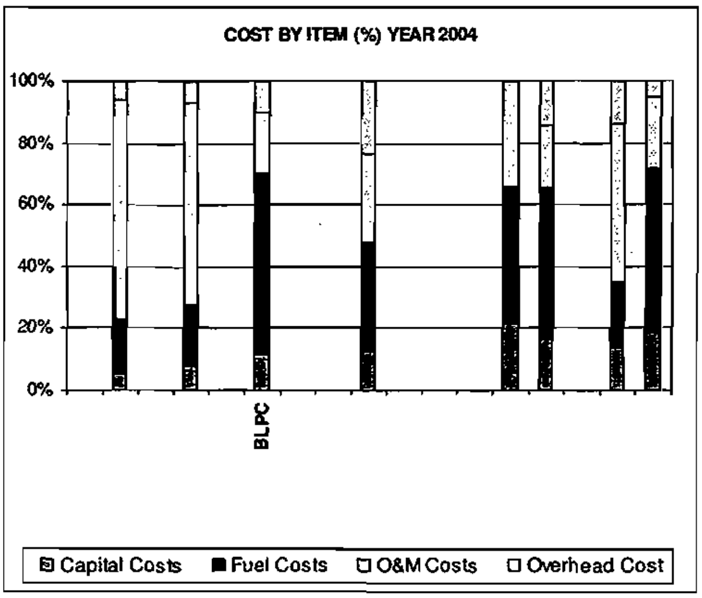


3.1.4 Cost Structure

The cost structure of participating utilities for the years 2002, 2004, 2005 and 2006 is presented by cost item in Figure 3, and by activity in Figure 4. The cost structure varies across utilities but there are common characteristics among them. Some differences might be explained for different ways in which utilities allocated costs by activity for this study.

Figure 3
Cost Structure by Item





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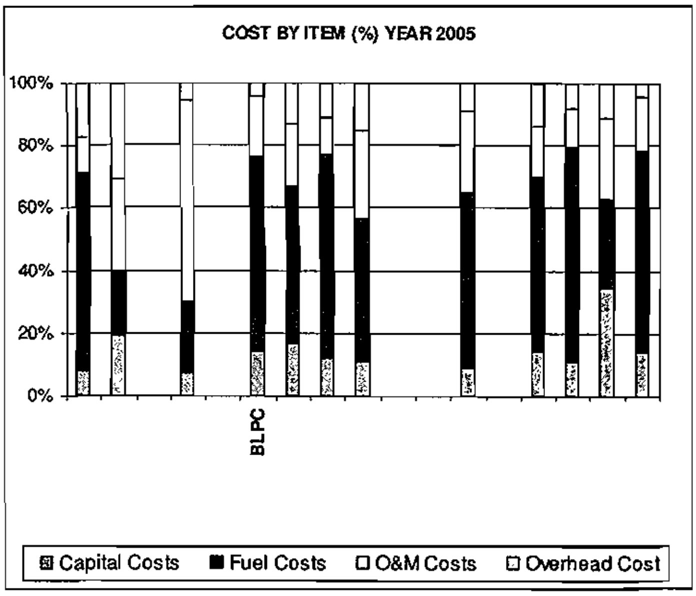


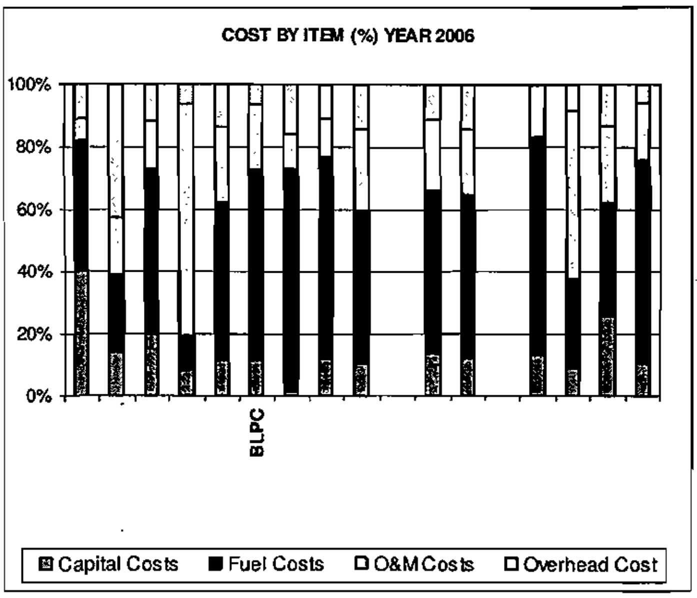
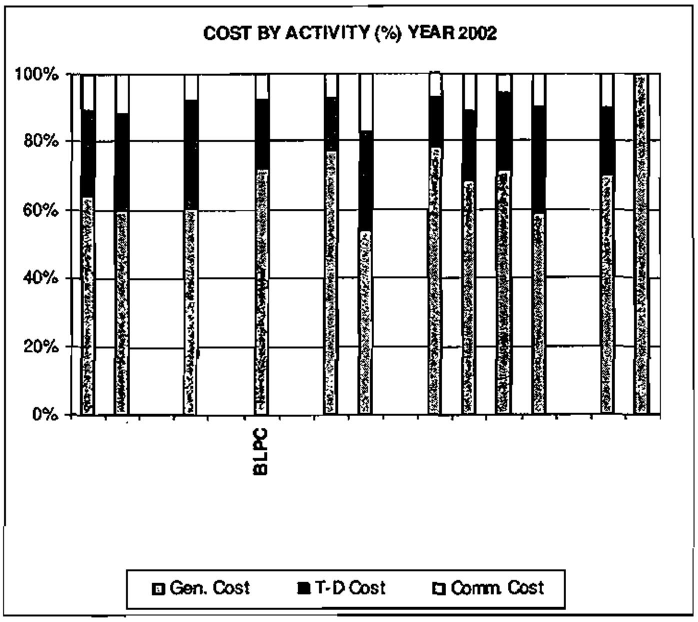
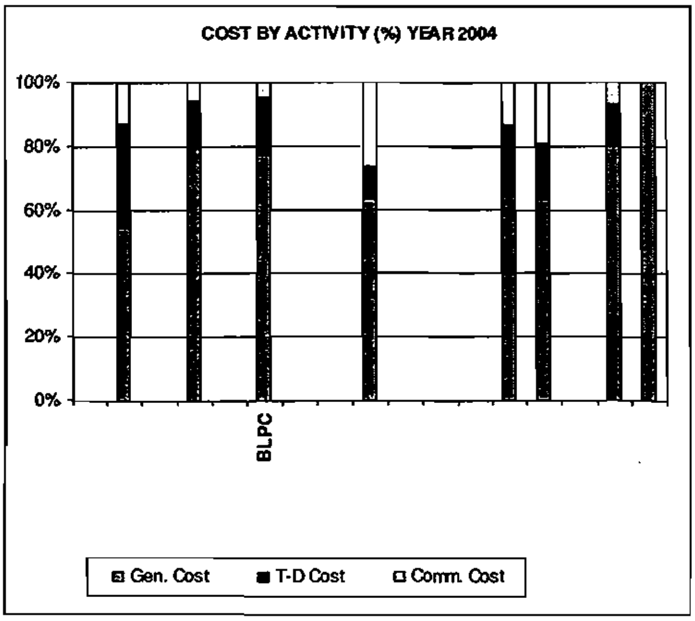
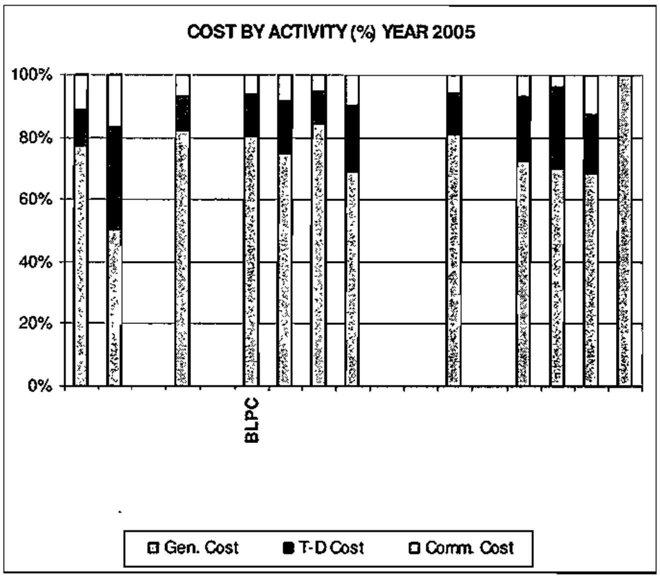
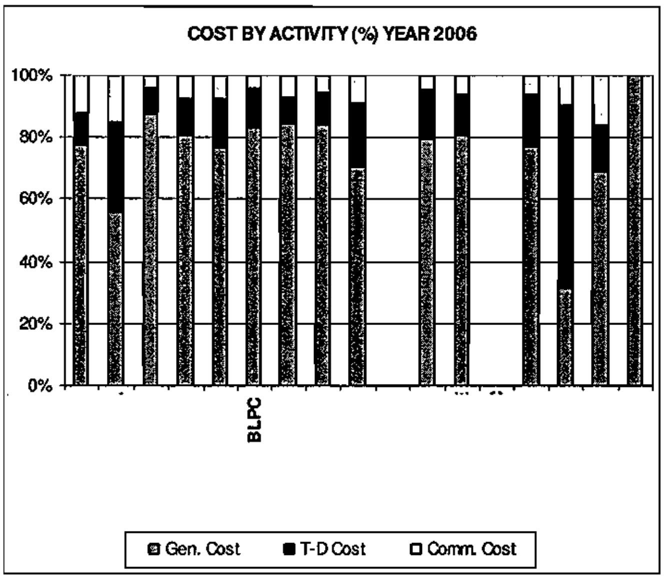


Figure 4
Cost Structure by Activity


COST BY ACTIVITY (%) YEAR 2002
100%
80%
60%
40%
20%
0%
BLPC
Gen. Cost
T-D Cost
Comm. Cost


COST BY ACTIVITY (%) YEAR 2004
100%
80%
60%
40%
20%
0%
BLPC
Gen. Cost
T-D Cost
Comm. Cost





In general, Fuel Costs and Operation & Maintenance Costs represent the highest item costs for utilities, each one accounting in average for 30 to 40% of total annual utility costs.

Generation is the highest cost activity representing in average around 60% to 70% of total utility cost, followed in lower proportions by Transmission-Distribution and by Commercialization. Over time, generation costs have increased as a result of higher fuel prices. This trend is applicable to all Caribbean utilities and to BLPC as well.

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The variation in cost structures between the reported information for the years 2002, 2004, 2005 and 2006 is not very significant.

3.1.5 Market Information

This section presents commercial information related to the markets served by the participating utilities. Table 10 shows consumption data and the composition of electrical consumption per type of customer for 2002, 2004, 2005 and 2006.

The market composition shows a high percentage of commercial consumption like in Barbados, mostly within the range of 40% to 60% of total consumption, explained by the electric loads of hotels and tourist facilities. Residential demand contributes to about 30% to 50% of total energy consumption. Industrial consumption is also important in the markets of some specific islands. The average annual growth rate between 2002 and 2006 for the region was 2.6% per annum. For Barbados the growth rate in this period was 3.9% per annum.

Figure 4
Consumption Data

Utility	Residential Consumption				Commercial Consumption				Industrial Consumption				Other			
	2002	2004	2005	2006	2002	2004	2005	2006	2002	2004	2005	2006	2002	2004	2005	2006
	28.9%	-	28.1%	41.4%	68.5%	-	67.9%	53.1%	0.3%	-	4.1%	5.5%	2.3%	-	0.0%	0.0%
	40.5%	40.3%	41.2%	41.2%	29.4%	27.0%	27.2%	26.4%	28.8%	31.5%	30.4%	31.2%	1.2%	1.2%	1.2%	1.2%
	-	-	-	47.8%	-	-	-	51.6%	-	-	-	0.0%	-	-	-	0.6%
	57.1%	57.4%	57.9%	56.6%	30.7%	31.2%	30.8%	32.0%	4.6%	4.0%	4.6%	4.9%	7.6%	7.4%	6.7%	6.6%
	-	-	-	43.0%	-	-	-	16.3%	-	-	-	40.2%	-	-	-	0.6%
BLPC	33.5%	33.2%	33.2%	32.6%	52.5%	53.7%	54.1%	54.7%	12.8%	11.9%	11.5%	11.5%	1.2%	1.2%	1.1%	1.1%
	-	-	33.3%	33.0%	-	-	60.0%	60.2%	-	-	4.1%	4.5%	-	-	2.6%	2.4%
	47.3%	-	46.6%	46.6%	51.7%	-	52.3%	52.3%	0.0%	-	0.0%	0.0%	1.0%	-	1.1%	1.1%
	50.3%	49.8%	49.4%	49.1%	39.2%	36.2%	36.9%	41.6%	7.0%	8.3%	8.1%	7.7%	3.5%	5.8%	5.6%	1.6%
	-	-	-	48.9%	-	-	-	19.4%	-	-	-	26.8%	-	-	-	4.9%
	31.0%	-	-	31.4%	34.7%	-	-	38.7%	31.4%	-	-	29.9%	2.9%	-	-	0.0%
	31.2%	n.a.	32.6%	32.6%	52.5%	n.a.	52.7%	53.9%	15.2%	n.a.	12.7%	12.9%	1.1%	n.a.	2.0%	0.6%
	40.8%	39.2%	-	39.8%	53.1%	57.1%	-	54.3%	4.6%	3.7%	-	3.9%	1.5%	0.0%	-	2.0%
	37.2%	36.1%	35.7%	35.7%	56.0%	56.9%	57.1%	56.6%	5.3%	4.6%	4.5%	4.6%	1.5%	2.5%	2.7%	3.1%
	-	-	25.6%	27.0%	-	-	9.4%	9.8%	-	-	64.6%	62.5%	-	-	0.4%	0.7%
	47.4%	47.4%	46.1%	46.3%	43.0%	44.2%	46.0%	45.7%	6.9%	5.9%	5.4%	5.6%	2.7%	2.6%	2.5%	2.5%

3.1.6 Generation Systems

The electric frequency in the region is either 50 or 60 Hz, depending on the adoption of European or American standards by the utilities.

Thermal generation is the predominant energy production technology found in the region. With the exception of some larger islands where natural gas and even coal is used for power generation and even coal, most of the generation is done with medium speed diesels and gas turbines using light fuel oil (diesel fuel) or in fewer cases with low ad medium speed diesels and steam turbines using heavy fuel oil as the primary energy source, which highlights the heavy dependence on this resource. Furthermore there are a few hydro generation units and some wind plants as well as rather small production from other renewable sources.

For planning and operation, most utilities apply N-1 and N-2 criteria to maintain generation reserves. A trend of using the more reliable N-2 criteria can be observed. Other reserve criteria reported include margins of 20 to 25% for operating reserves and some fixed values for spinning reserves. Some utilities reported using Loss of Load Probability calculations for planning purposes.

At BLPC there is a Spinning Reserve Policy to have a spinning reserve capacity of 5 MW available. For expansions BLPC calculates the Loss of Load Probability which may not exceed a total of 1 day per year.

3.1.7 Transmission & Distribution Systems

Transmission and distribution are treated together in the Caribbean Benchmark Study, mainly due to the relative short distances between production and consumption centers in the islands and the low voltages used for energy transportation.

At BLPC the highest voltage is 69 kV for the Transmission System (ring configuration) and furthermore there are 24 kV systems (T&D, ring and radial) and 11 kV for Distribution where most feeders can be ringed and are normally operated as radial. The 69 kV transmission system is fully underground, the other systems mainly overhead.

3.1.8 Customer Services

Different customer services are offered by the utilities as described below.

Service points: Besides the central administrative offices, utilities have one or several service points (number depends on customer base and geography) to conduct customer related business including payment collection, bill inquiries, connection and reconnection requests and technical service requests. In general, customers can also pay their bills at post offices, banks and other financial offices or authorized collection points.

BLPC has 2 offices and the total number of cashier/ receptionists is approximately 12. But there are over 70 other locations across the island where customers can pay their bills. These include banks, department stores, supermarkets and other retail outlets.

Call Centers and Emergency Lines: All utilities have at least one emergency line to receive urgent requests of technical service. The most common configuration is a PBX equipped with several lines where customer requests are directed to the respective departments (20 lines at BLPC). Some utilities have call centers with several operators and automatic systems with response and recording capabilities. At BLPC one call center staffed by 9 representatives to answer customer queries and complaints as they relate to billing. The call center is open Mon – Fri 8.00 a.m. – 4.30 p.m. There is also an emergency service center which is manned 24 hours a day. This is staffed by 3 persons during normal office hours and 2 persons at all other times. Calls to both of these centers are routed through an Automatic Call distribution telephone system with 10 telephone lines to the call center and 4 telephone lines to the emergency center. This system provides management reports that include statistics on the volume of calls, the average speed that calls are answered, number of calls abandoned etc.

Trouble calls and other customer requests are directed to and handled by the respective service departments. A few utilities use databases, work order systems or customer information systems to record and keep track of complaints and requests. At BLPC trouble calls are input into the work management system "Maximo" where they are tracked and managed.

Online services: Some utilities like BLPC have active websites with corporate information. The online services offered are mainly account information, enquiries reception and service applications. Two utilities offer electronic billing.

Three utilities reported the utilization of hand held devices for meter reading and one utility the application of automatic meter reading technologies. Meters are read monthly with different cycles for the majority of the utilities. BLPC applies monthly reading (industrial, partly commercial clients) or bimonthly reading (residential, partly commercial clients), but billing is monthly to all clients. One utility reported monthly or each four months readings depending of the type of customer. According to the information supplied by the utilities, the number of non-metered customers is marginal.

Customer bills are produced in an automated way or using computer software like at BLPC, and distributed monthly for the majority of the utilities. The reported collection lags vary from company to company but are rather high; they are in the range of 15 to 77 days in the low side (22 days at BLPC, which is quite good) and up to 180 days in the high side.

Customers of BLPC can make requests for new connections, reconnections etc. in person at one customer service office or by letter; these are all entered into the Customer Information System where they are tracked and managed.

3.2 Performance Indicators

3.2.1 Performance Areas and Definitions

The performance indicators have been categorized into groups as follows:

- General indicators;

- Generation indicators;
- Transmission-distribution indicators;
- Commercialization indicators.

Within each group, indicators are classified as technical, economical, financial and organizational. The definitions of the performance indicators used in this study are presented in Annex 1.

3.2.2 Presentation of Results

The results of the calculations for the performance indicators for the years 2002, 2004, 2005 and 2006, are presented in the following Figures. All the indicators were calculated on an annual basis. Per indicator, the trend in BLPC's during the years 2002, 2004, 2005, and 2006 is shown as well as the trend in the performance of all other companies (e.g. the average excluding BLPC). Also, the individual performance per company in 2006 is shown in the Figure in anonymous format. Per indicator, all companies other than BLPC have been ranked and accordingly coded "A", "B", "C", and so forth. The performance of BLPC in 2006 is indicated by a red line and helps to identify where BLPC stands relative to its Caribbean counterparts (blue bars and line).

3.3 Results of the Comparative Analysis

3.3.1 General Indicators

The General performance indicators as defined and calculated in Annex 1 are analyzed in the following numerals. Per performance Indicator commentaries on BLPC's performance have been given and where appropriate recommendations have been added.

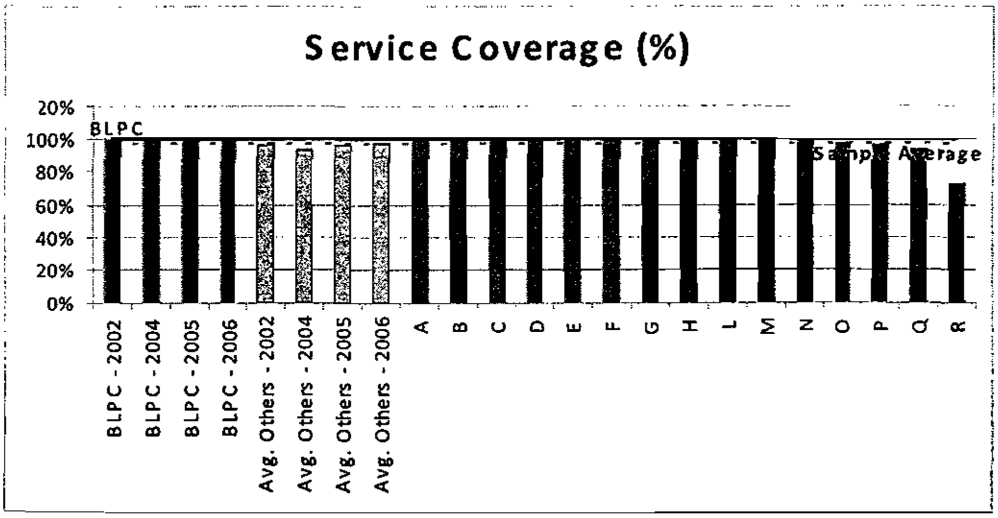
3.3.1.1 Service Coverage (GL.1)

The Service Coverage indicates the percentage of consumers with an electricity connection. Given the social and economic importance of electricity, coverage of 100% can be considered the best-practice target,

Several utilities reported a Service Coverage of 100% whilst others (except a few) reported values slightly below 100%. In general the region has a very high coverage of electrical service which is facilitated by the relative small size of the islands. The mostly 100% service coverage indicates that the island utilities are mature companies without major expansion needs except for regular load growth.

BLPC belongs to the category of islands that has a 100% service coverage implying that in Barbados, all consumers (if requested) have access to an electricity connection. The best-practice 100% coverage has been consistently maintained during the period considered.

Figure 5.
Service Coverage



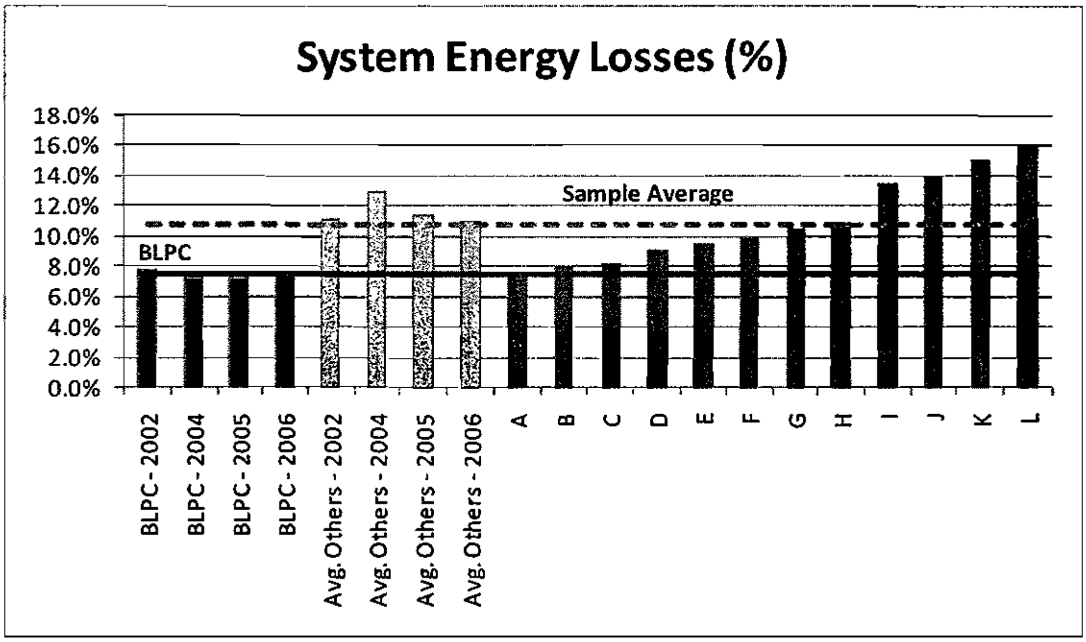
3.3.1.2 System Energy Losses (GL.2)

The amount of energy losses as a percentage of total generated and/or purchased energy is a measure of technical efficiency of utility service. Relatively low losses are advantageous as this requires less production to cover the losses and hence result in lower costs and higher efficiency. Low losses are particular important in the face of high fuel prices.

Average System Energy Losses in the sample are around 11%. Although the regional average is still higher than the average in for example the US (around 6%), this can be classified as rather good performance.

BLPC's performance of 7.5% is substantially better than the average, is quite close to the average in the USA and is (apart from one other utility) the best in the region. The low level of losses is favorable for Barbados as this implies lower generation costs per unit of kWh sold.

Figure 6
System Energy Losses



3.3.1.3 System Load Factor (GL.3)

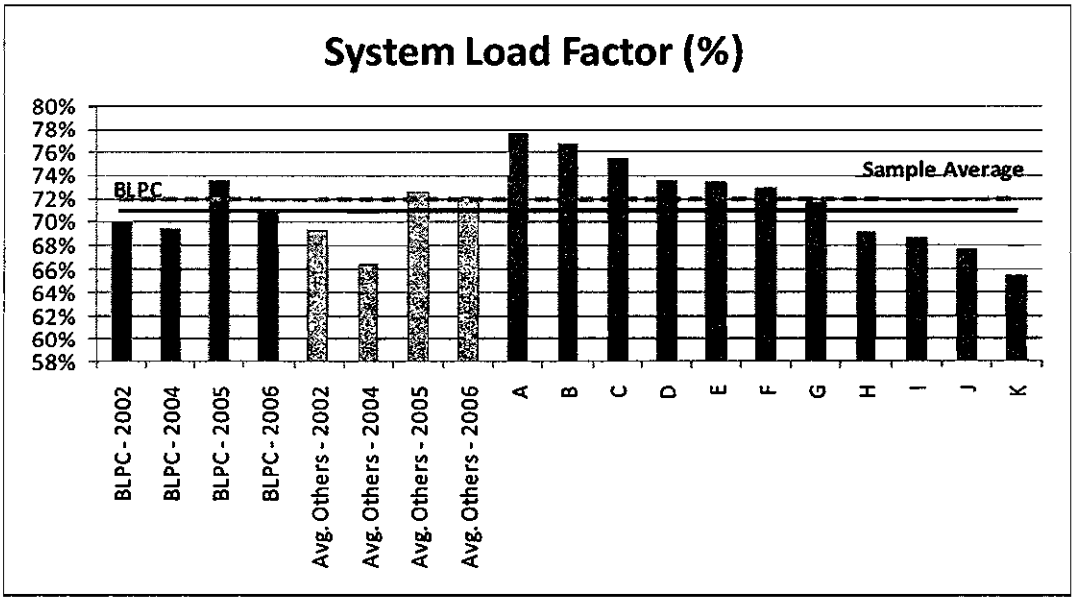
The load factor is an indication of the difference between the peak loading of the system and the average load throughout the year. As demand will fluctuate over time as a function of different factors (time of the day, day of the week, weather, etc.) there will necessarily be a difference between peak and average loading. The load factor is an indication of how high this variance in demand is with a lower load factor indicating more variance and conversely.

The regional average System load factor was 72% and varies between 65% and 78% from utility to utility. The load factors across the region are generally similar, reflecting the characteristics of load demand on the islands. The average load factor of 72% can be classified as rather high and indicated a better utilization of the capacity of electrical facilities in the region.

BLPC's load factor of 71% is more or less the average of the region and is at a level that would normally be expected.

KEMA

Figure 7
System Load Factor



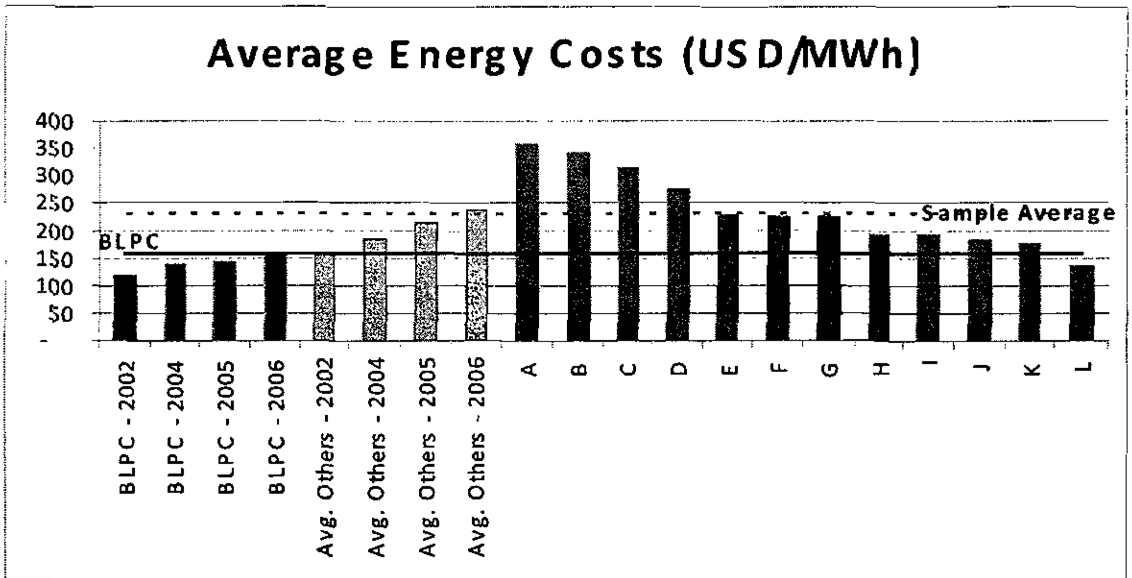
3.3.1.4 Average Energy Cost (GL.4)

Average energy costs are defined as the total costs incurred by the utility divided by the total amount of energy produced. Clearly, lower energy costs are desirable as this corresponds with higher economic efficiency. At the same time, one should take into account the fact that energy costs will be driven to a substantial degree by international fuel prices.

The general trend in fuel prices has been upwards in the period 2002 – 2006 and this is clearly reflected in the increase in average costs in the region. This trend applies to the average of the region and to BLPC as well. However, the increase in BLPC's costs is less steep than the region whilst BLPC's costs are generally lower as well. This can partially be explained by the higher demand in Barbados as compared to other islands which results in some relative scale economies. This is also the explanation for the significant differences in average energy costs across the region. Furthermore, BLPC commisioned two new 30 MW low speed diesel generators in 2005, thus increasing heavy fuel oil burning capacity by 60 MW on more efficient generation at a time when fuel prices started to climb.

BLPC's costs are in the order of 150 USD per MWh which is among the lowest in the sample. Again, this is likely the effect of relatively higher load levels and provides an important advantage for BLPC in lowering its costs. As fuel prices increase further the impact of this will nevertheless still be visible in the average costs for BLPC although this impact will be proportionally less than in other islands.

Figure 8
Energy Cost



3.3.1.5 Customer Service Rates

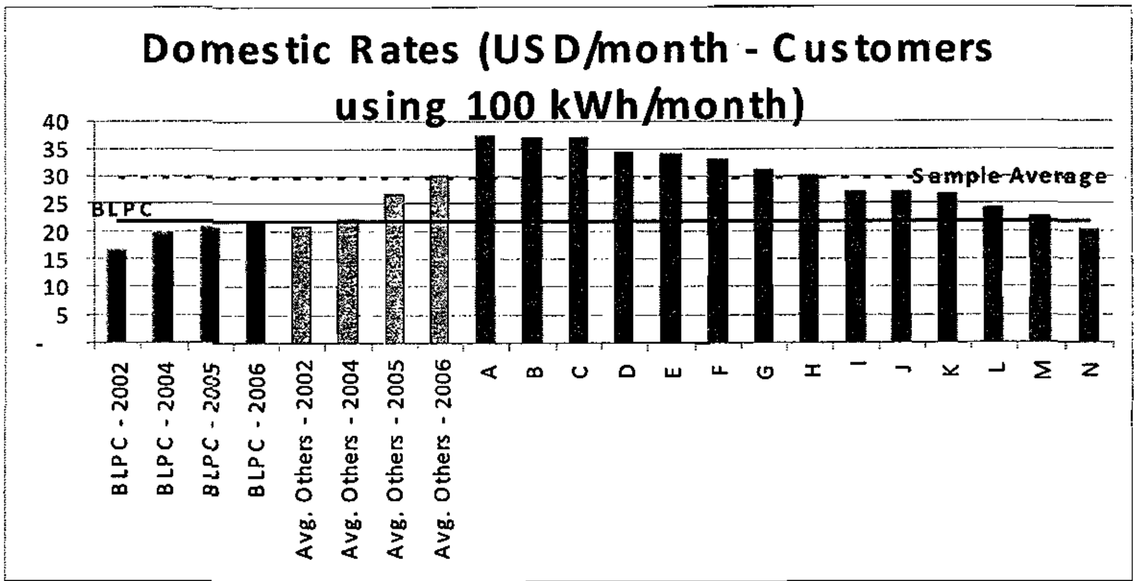
In general, service rates are consistent with energy costs, allowing the utilities to recover their costs and finance their operations. In some cases customer rates show important differences in percentage terms, these differences may reflect social and tax policy regarding electricity supply and constitute a competitive factor for the island economies.1

In the following figures, BLPC's tariffs for domestic customers allow for 10% prompt payment discount and include 15% VAT. Commercial and Industrial bills exclude VAT as this can be reclaimed as "Input VAT".

Electricity rates show an increasing trend over years, which reflects the increase in fuel prices. The increase is more or less uniform across the customer groups. The increase is also notable for BLPC. However, the increase for BLPC is proportionally lower than for other utilities. Also, as can be observed, BLPC's rates are generally leaning towards the lower end of the sample.

[1] We should note that the following comparisons exclude one of the participating utilities as its electricity rates are heavily subsidized and comparisons would provide a distorted picture.

Figure 9
Domestic Rates



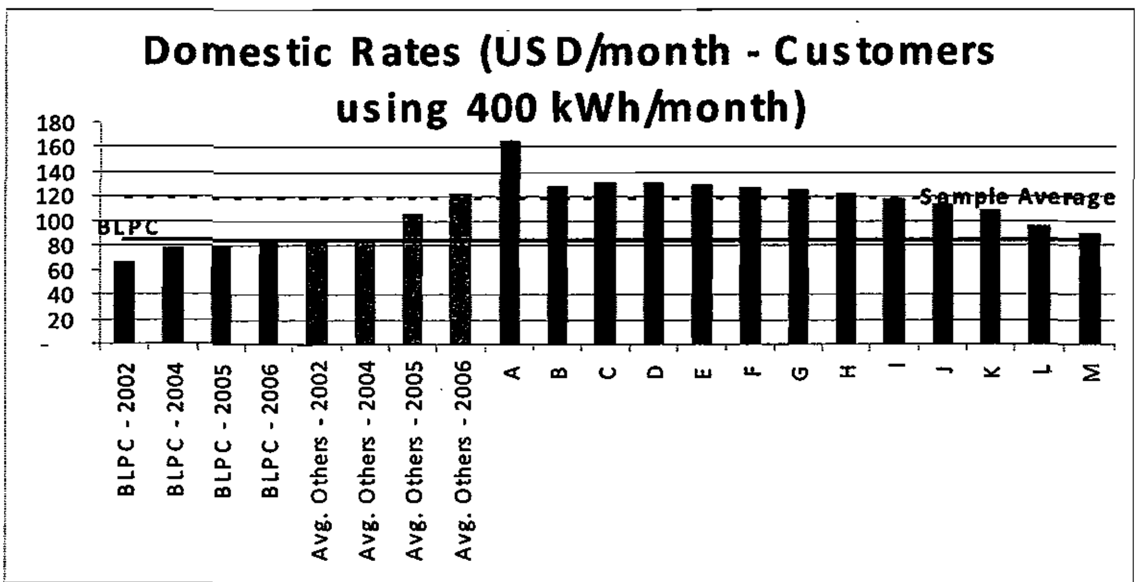
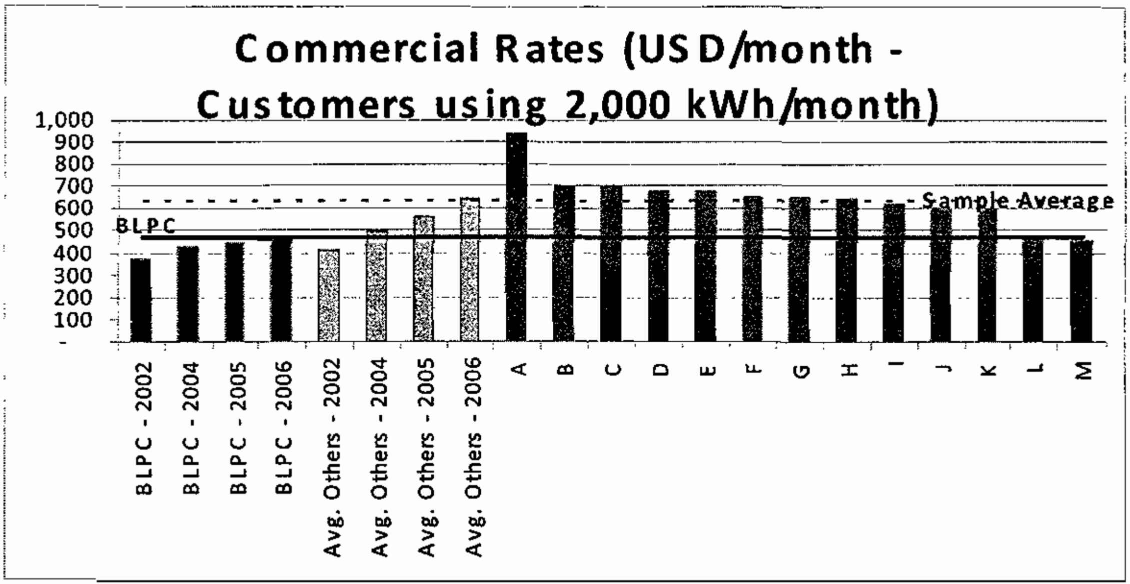


Figure 10
Commercial Rates



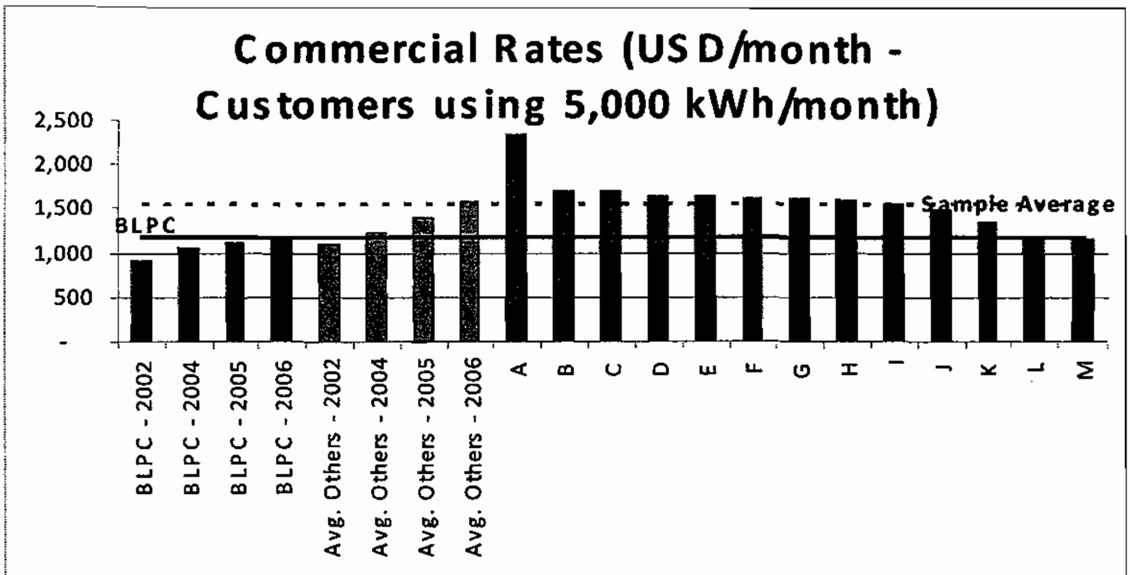
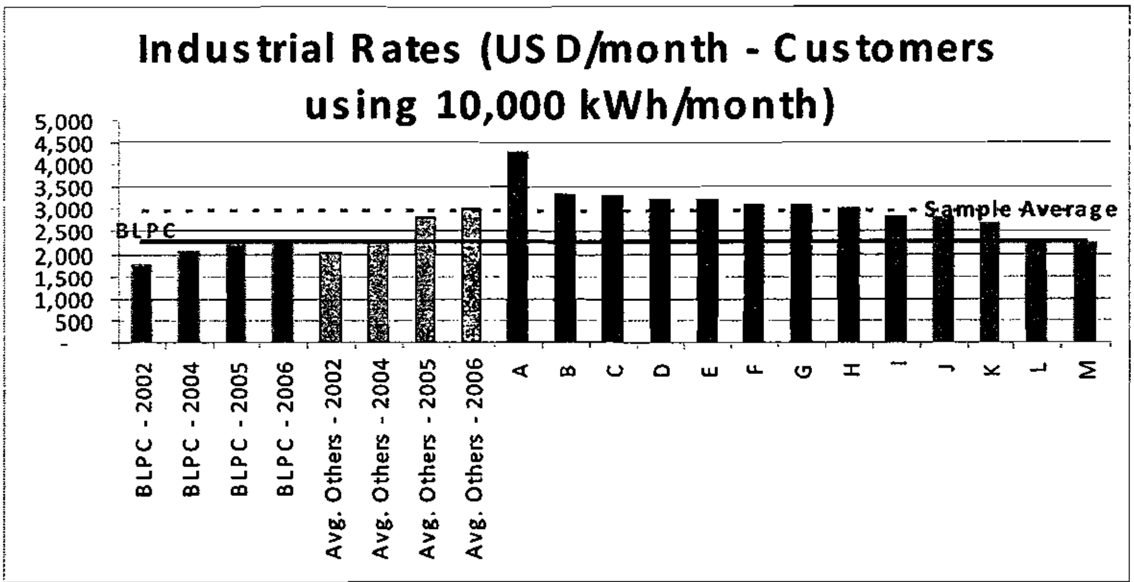
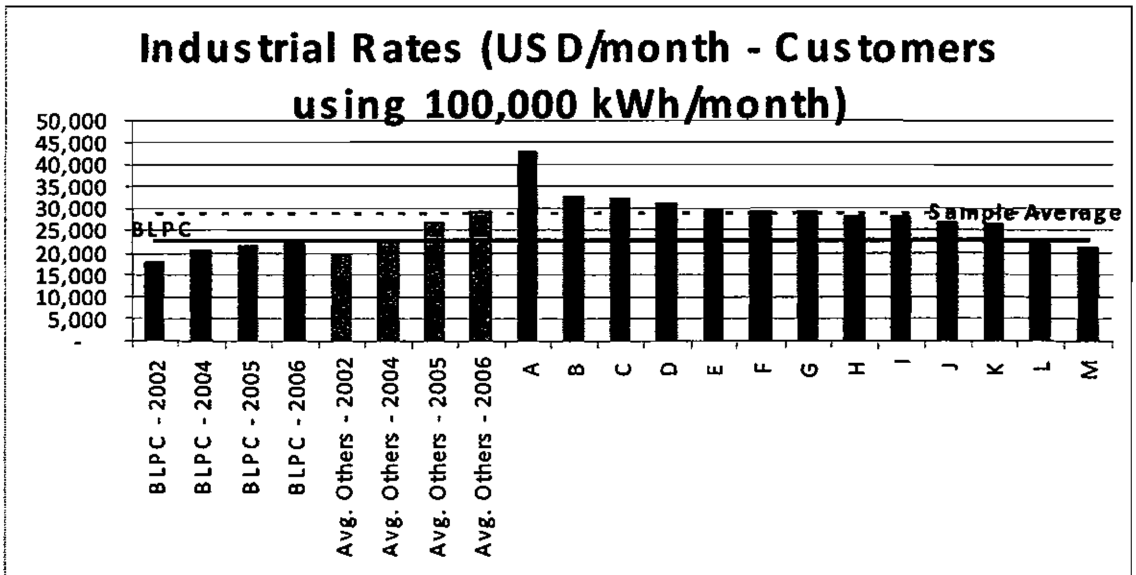


Figure 11
Industrial Rates





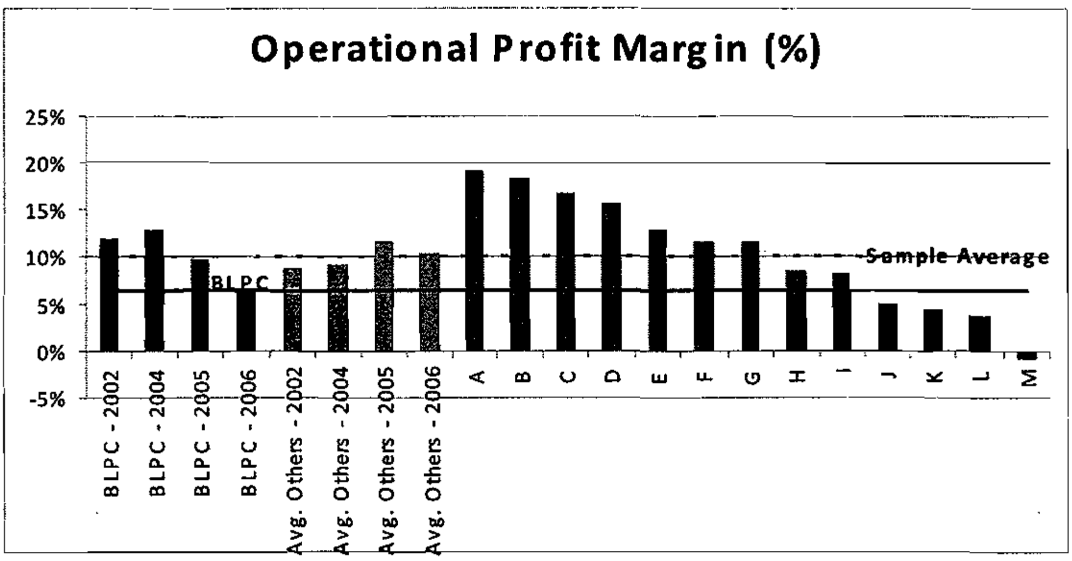
3.3.1.6 Operational Profit Margin (GL.6)

The operational profit margin indicates the level of net income generated by the utility in relation to the revenue. The profit margin is an indication of the profitability of the utility. Defining a best-practice range for the profit margin is difficult as this will depend on the financial structure of the company. In general however, profit margins between 10% and 20% are common in the utility industry.

The regional average operational profit margin in 2006 was around 10% which is at the low side of the expectation spectrum but nevertheless still acceptable. Over time, the profit margin for the region has remained more or less stable with some slight variations around the 10%.

For BLPC, the profit margin in 2002 and 2004 was at reasonable levels around 12%. Starting in 2005 however, the profit margin has been decreasing to a low 6% in 2006.

Figure 10
Profit Margin



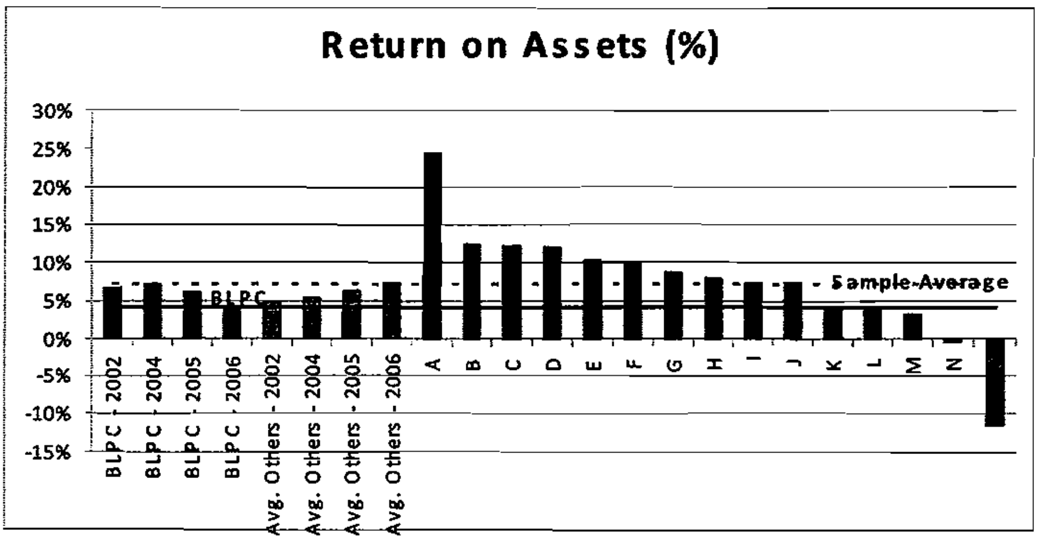
3.3.1.7 Return on Assets ROA (GL.7)

The return on assets measures how effectively assets are used to generate a return on investment. Note that only fixed assets are considered. The expected range for this indicator depends on the opportunity cost of capital, that is, the return expected in alternative investments with similar risk. The Weighted Average Cost of Capital (WACC) is the most common method used for calculating the fair rate of return of a business. The WACC will vary as a function of risks faced by the utility, which in turn depends on factors such as regulatory framework, macro-economic stability, and access to capital markets.

The regional average ROA is around 7% and more or less stable over time. This is lower than what would strictly speaking be expected. However, the lower ROA can partially be explained by socio-economic considerations whereby governments try to maintain low electricity tariffs which however comes at the expense of lower than economic returns.

The ROA for BLPC has been relatively low and has shown a decrease in 2005 and 2006. In 2002 and 2004, the ROA was around 7% which can already be considered low. Although more detailed analysis would need to highlight what the appropriate ROA for BLPC should be, a level of 7% seems to be low taking into consideration international experience.

Figure 11
Return on Assets



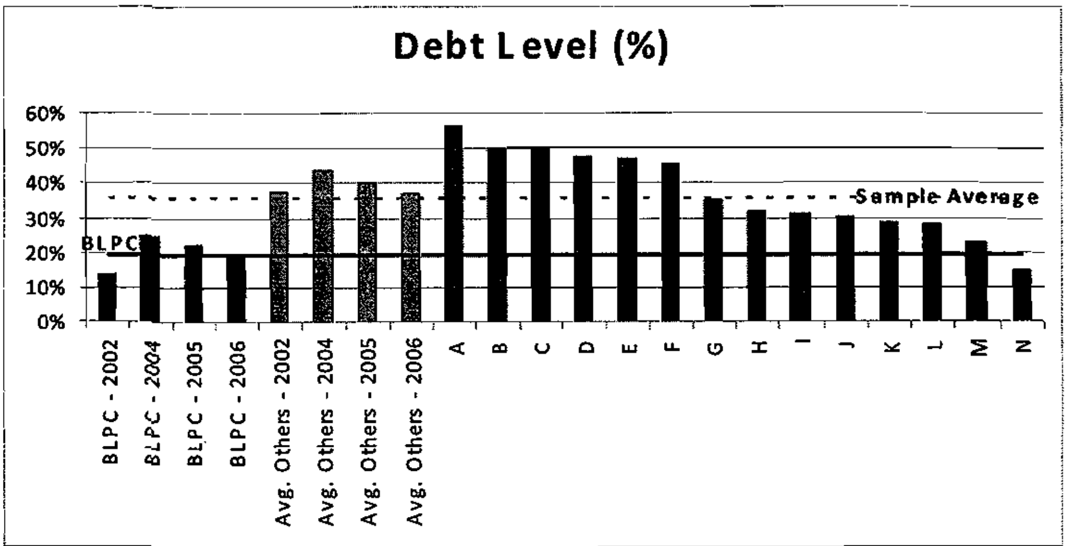
3.3.1.8 Debt Level (GL.8)

The capital structure is essential to evaluate its long-term risk and return prospects. Since debt carries fixed-interest and repayment commitments, a highly geared firm (i.e. a firm with large fraction of debt in its capital) has greater chances of failing on its financial commitments and being forced into bankruptcy. As such, highly leveraged firms are more vulnerable to business downturns than those with lower debt to worth positions. A low debt level on the other hand indicates that the business is making little use of its potential leverage and is relying too much on more expensive equity. Generally, for the utility industry, a debt level of between 35% and 65% is considered to be the normal range.

The regional average debt level is around 36% which is leaning towards the minimum expected range. Debt levels show large fluctuations though and range from 15% to 56%.

The debt level of BLPC is relatively low at 20% and has decreased since 2005. The significant increase from 2002 to 2004 is possibly explained by a large loan attracted in that period.

Figure 12
Debt Level



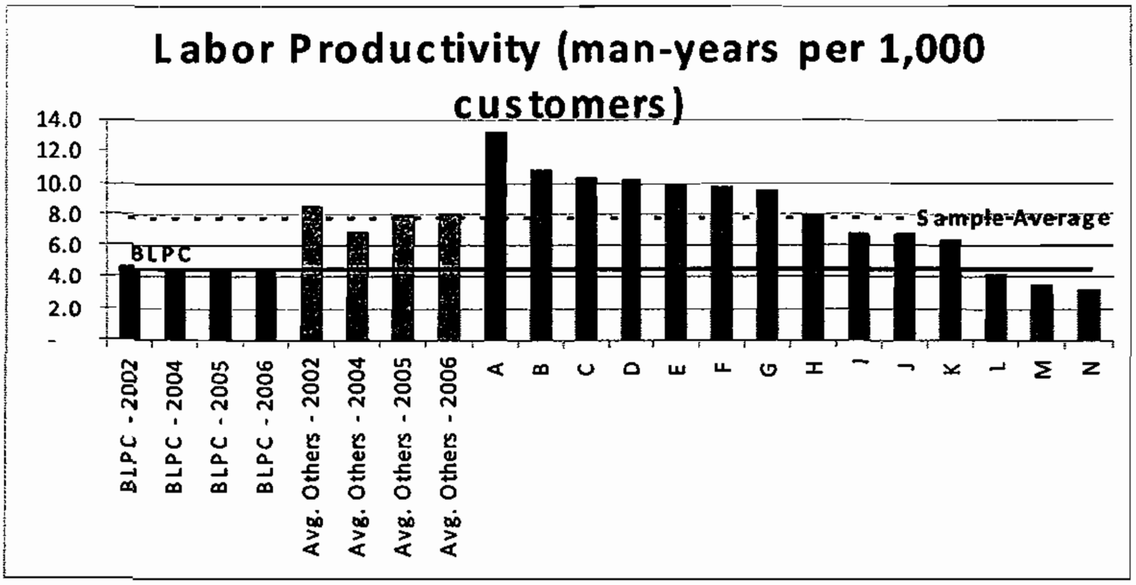
3.3.1.9 Labor Productivity (GL.9)

Labor productivity is expressed in the number of man-years per 1,000 customers. The number of man-years is derived from the full-time-equivalent figure. A lower value implies higher productivity as less staff is required to serve the same amount of customers.

The average labor productivity in the region is 7.8 man-years per 1,000 customers. There is significant variation across the region with the most productive utility having a level of 13.2 and the least productive one 3.2 man-years per 1,000 customers.

BLPC's productivity is significantly higher than the region's average and stands at a level of 4.5. The performance is also consistent over time and has remained at more or less the same level in all years. Explanations for BLPC's good performance can be the relatively higher demand level as well as genuine higher productivity within the company.

Figure 13
Labor Productivity



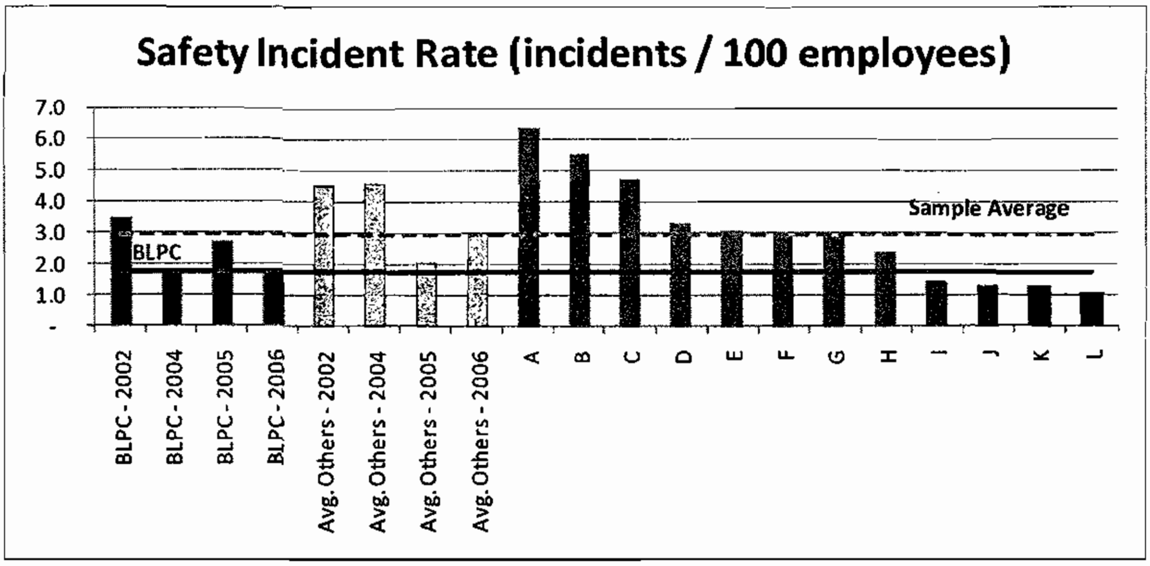
3.3.1.10 Safety Incident Rate (GL.10)

The safety incident rate is defined as the number of safety incidents divided by 100 employees. The general aim would be to minimize the safety incident rate as much as possible.

The average safety incident rate in the region is 2.9 incidents per 100 employees. There is however a large variance in the safety incident rate throughout the sample as well as over time. This can be explained by the relatively low number of incidents, which tends to result in higher variance (i.e. standard deviations). This makes the comparisons more difficult.

Over time, BLPC's performance varies between 1.8 and 3.5 incidents per 100 employees. In all years except 2005, BLPC scores better than the average in the region. In the year 2006 the safety incident rate is also significantly better than a number of the other utilities.

Figure 14
Safety incident rate



3.3.2 Generation Indicators

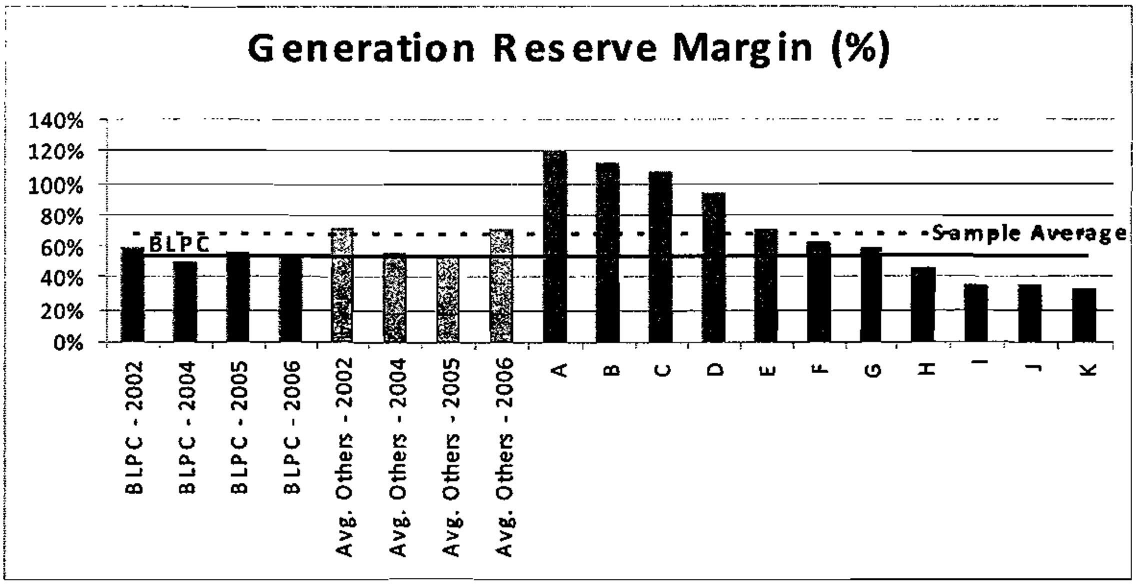
3.3.2.1 Generation Reserve Margin (GN.1)

The Generation Reserve Margin is defined as the relative difference between the total installed generation capacity within the system, and the system peak load. A higher margin implies a lower utilization rate of available generation capacity. A lower margin is however not necessarily "better" as reserves are required to assure a secure and reliable operations of the power system. If the margin becomes too low, the probability of black-outs will increase as there is less reserve in the system in case of generator outages. Generally, the reserve margin will tend to decrease when the power system is larger as larger systems also tend to be more robust. Typically, mainland systems are interconnected and reserve margins can also be kept at a lower level since interconnected systems can provide back-up to each other.

The average reserve margin of the peer group is around 70%. There are large differences between islands which is a direct result of the differences in scale. Generally, the larger islands have lower margins while the smaller islands have margins even close or higher than 100%.

For a power system of the size in Barbados one would expect a reserve margin around 50%. BLPC's reserve margin is 54% which is in line with expectations. Over time, as the system grows, a lower margin may become more appropriate. However, the answer to what an optimal margin is would depend on a thorough power system planning analysis rather than simply being derived from a comparative analysis.

Figure 15
Generation Reserves



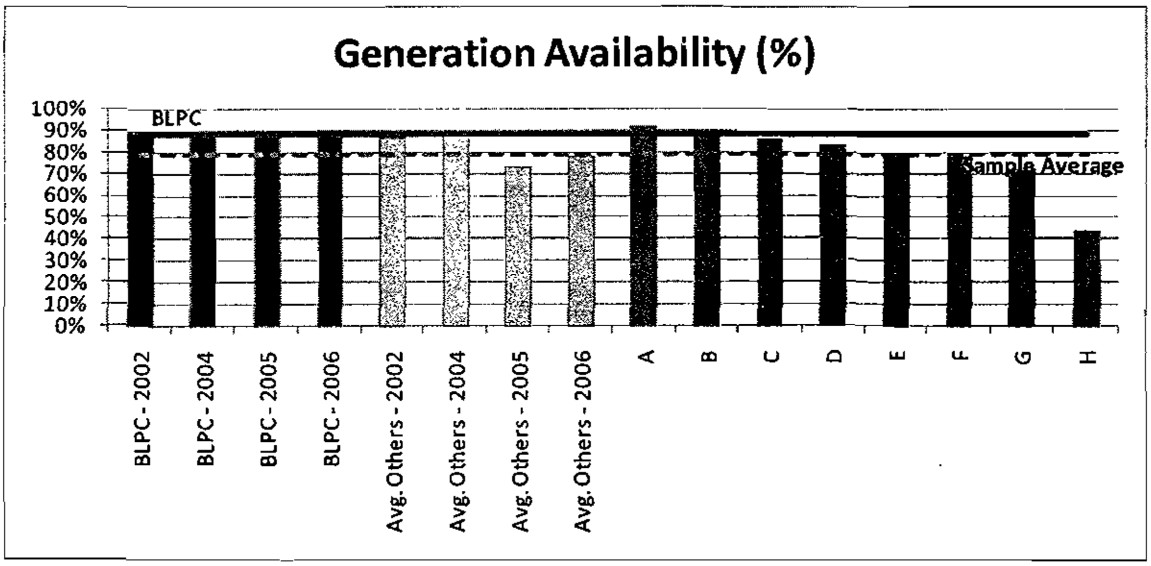
3.3.2.2 System Equivalent Availability (GN.2)

The generation availability indicator shows the availability of system generation capacity. In practice, any generating unit will not be available 100% of the time as outages are practically unpreventable. These outages can either be scheduled (e.g. because of maintenance) or forced (e.g. because of a fault). The Generation Availability indicator represents the weighted average availability of all generators present in the system. If the average age of the units is higher, the availability tends to go down as older units require relatively more maintenance and are also more likely to experience faults.

The average availability in the region was around 80% which is what could be expected on average. Apart from a few utilities, generation availability seems to be reasonable.

For BLPC the generation availability is 88% which is higher than the average. The availability is also consistent over time.

Figure 16
Generation Availability



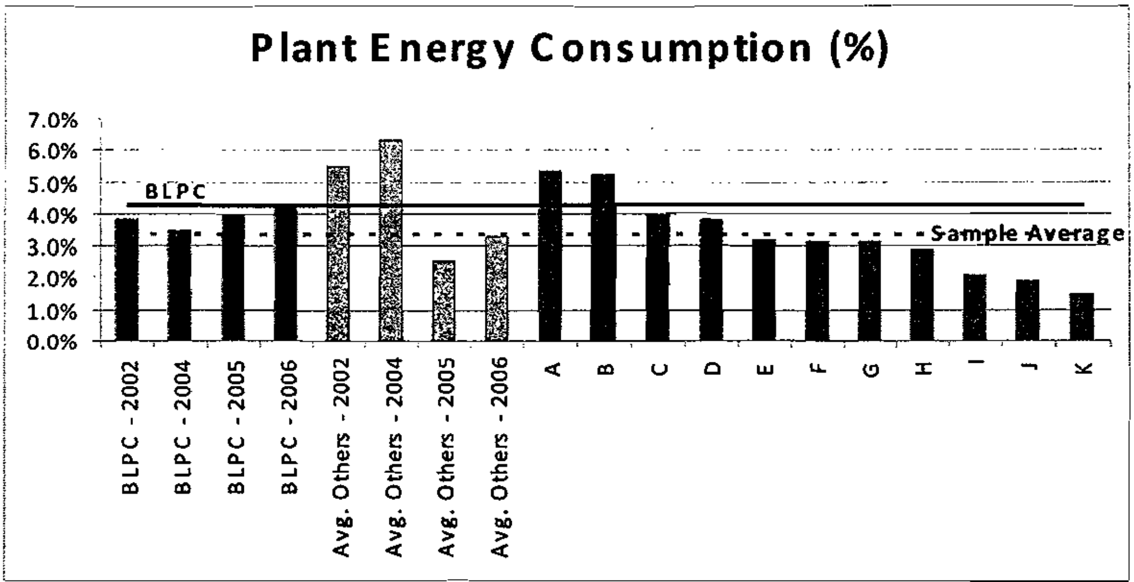
3.3.2.3 Plant Energy Consumption (GN.3)

Plant energy consumption (also called self-usage or station losses) is the amount of electricity used by the generation plants itself when producing electricity. Lower station losses are desirable as this implies that relatively less fuel is used to operate the plant.

Average plant consumption in the region is around 3% with variations between 1.5% and 5.3%. We should note that for comparison purposes, utilities engaged into combined electricity-water production are excluded as this would provide biased outcomes.

BLPC's plant consumption is 4.3% which is higher than the region's average. See for the graph figure 17 at the next page.

Figure 17
Plant Consumption

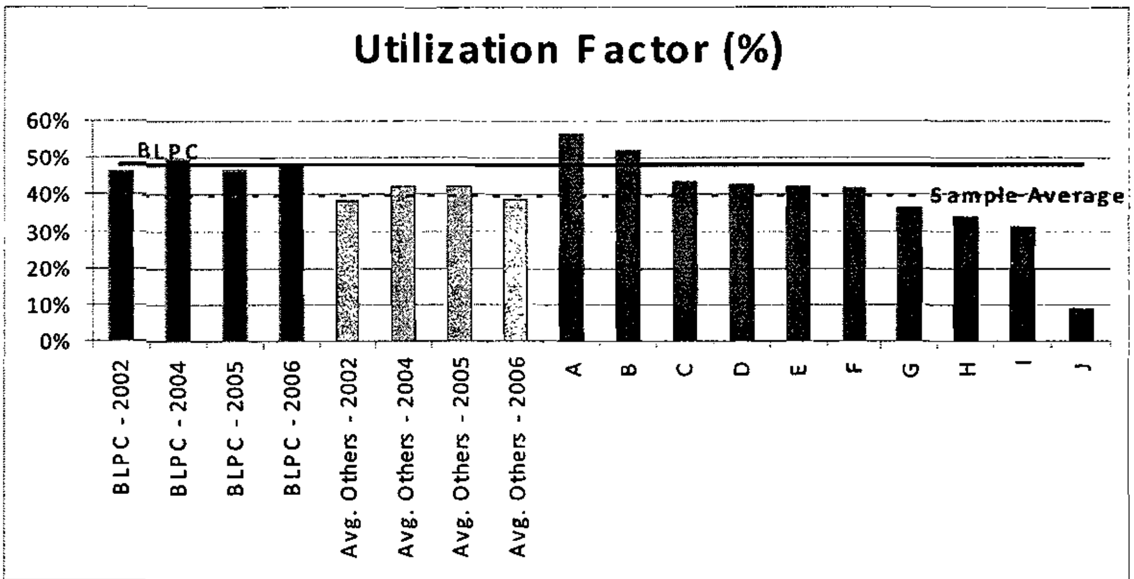


3.3.2.4 Utilization Factor (GN.4)

The utilization factor for generation is defined as the amount of electricity actually generated divided by the theoretically amount of electricity that could have been generated. The latter is defined by the total installed generation capacity (in MW) times 8760 hours (the number of hours in a year). A higher utilization factor indicates that more use is made of existing capacity. However, we should note again that a higher utilization factor may also imply a lower degree of reserve in the system (note the parallel with the generation reserve margin indicator).

The average utilization factor in the region is 40%. BLPC has a utilization factor of 48% which is higher than average and among the highest in the sample. This high factor can be explained by the relative high demand in Barbados as compared to other islands and subsequent higher economies of scale.

Figure 18
Utilization Factor

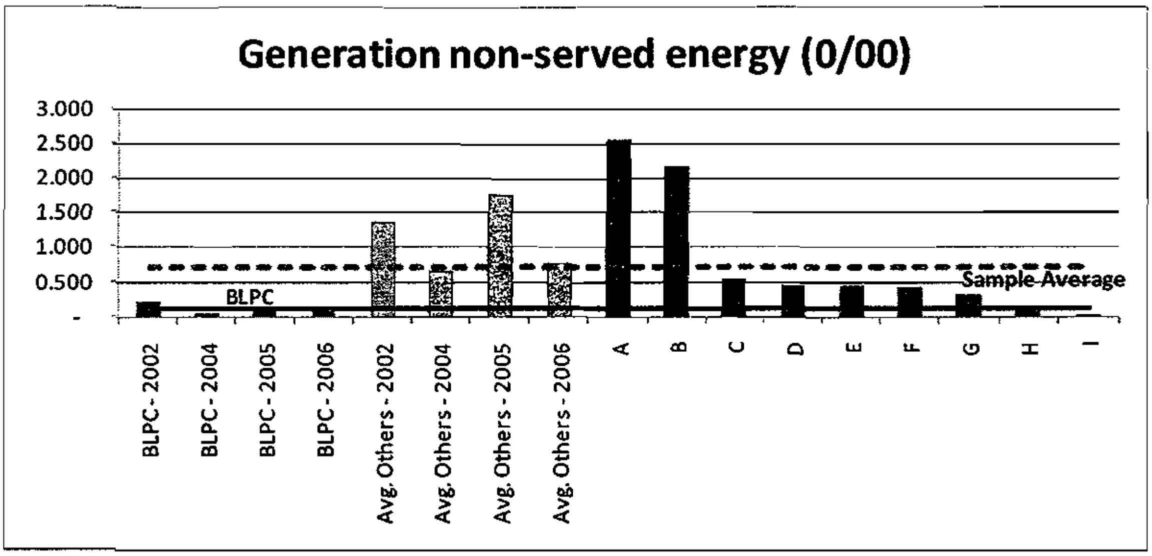


3.3.2.5 Generation Non-Served Energy (GN.5)

The generation non-served energy indicates the amount of electricity not served due to generation outages relative to the total amount of electricity demanded (i.e. electricity supplied + electricity non-served). As this number tends to be very small, it is expressed in per-thousands rather than percentages. Generally, a lower level of non-served energy is desirable. However, there is some natural level of non-served energy as a value of zero (all electricity served) would suggest over-investment in the power system. Quantification of the optimal level of energy non-served can be performed using socio-economic analysis. This, however, is out of the scope of the analysis here.

The average non-served energy in the region is 0.715 o/oo but with large variations and with two utilities experiencing a much higher degree of non-served energy than others. For BLPC, the level of non-served energy is at the low end of the sample and significantly lower than average.

Figure 19
Generation Non-Served Energy

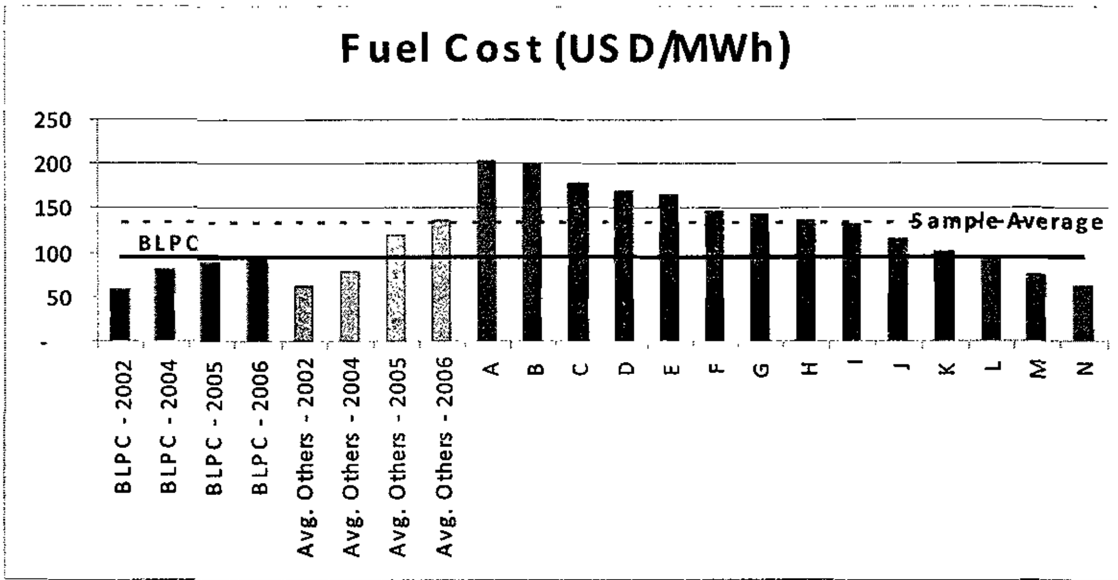


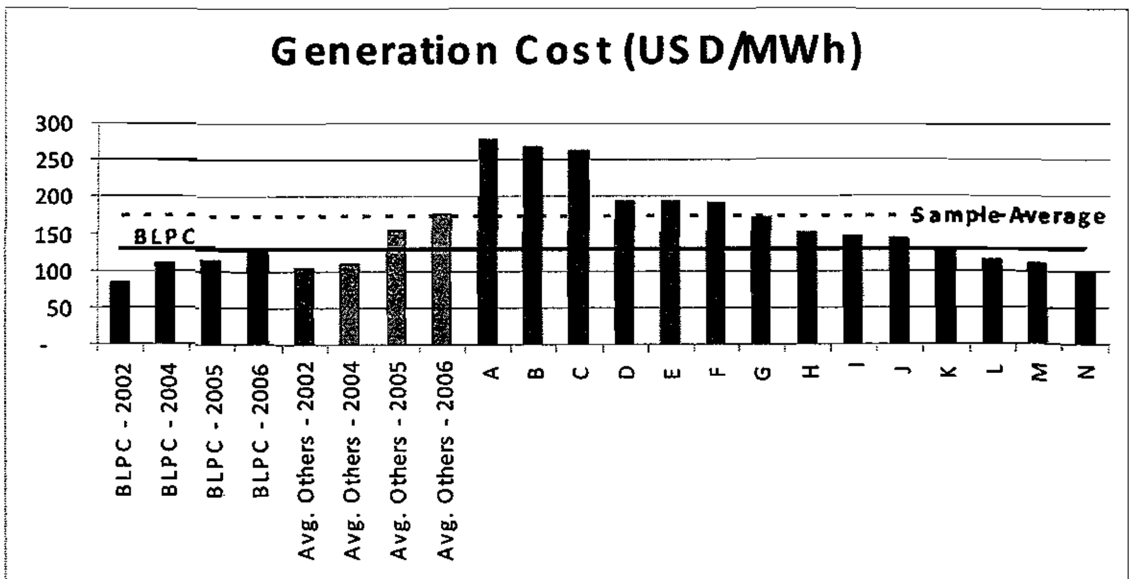
3.3.2.6 Fuel and Generation Cost (GN.6 and GN.7)

The fuel and generation cost indicators are defined as the average fuel costs involved in producing one kWh of electricity (fuel cost) and the average total cost of producing one kWh, including capital costs. These generation indicators are strongly driven by the international fuel prices which directly influence the generating costs.

For the region one can notice a steady increase in fuel costs over time, reflecting the increase in fuel prices. This trend also applies to BLPC. As noted previously however, the increase in fuel costs for BLPC is relatively lower due to better economies of scale and the significant use of heavy fuel oil in the generation mix relative to other utilities.

Figure 20
Fuel Cost





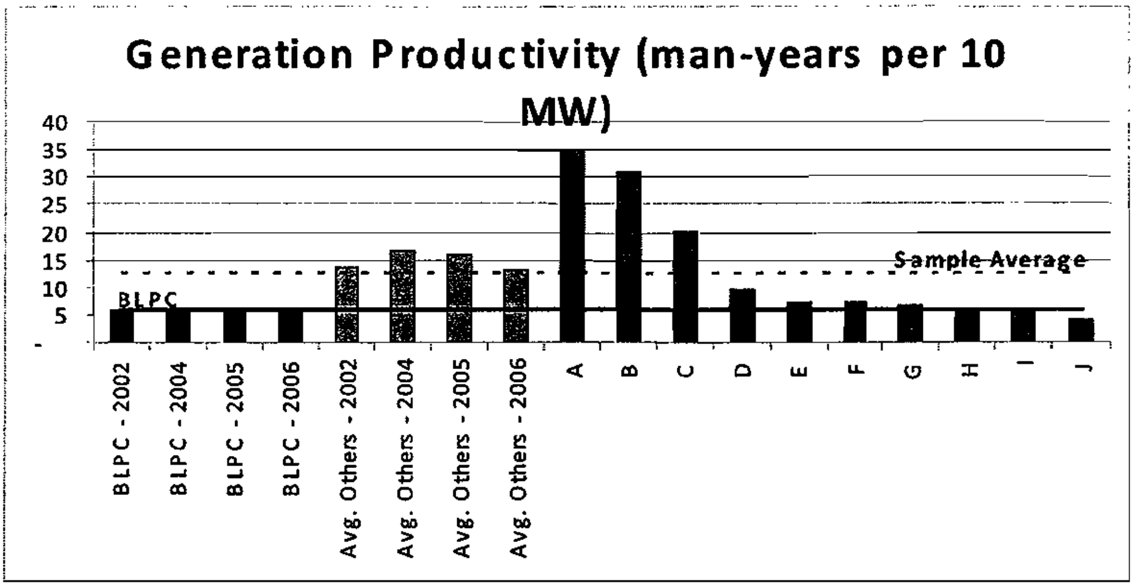
3.3.2.7 Generation Productivity (GN.8)

Generation productivity is defined as the number of man-years per 10 MW of installed generation capacity. A lower value indicates higher productivity.

The regional average value of generation productivity was 11.5 man-years per 10 MW. The sample can roughly be divided between two groups. First one group with relatively high productivity in the order between 4 and 7 man-years per 10 MW. Second, a group with productivity levels of more than 7 man-years per 10 MW. Differences in scale are an important driver for these different productivity numbers.

For BLPC the generation productivity is 5.95 which is comparable to the first group of more productive utilities. Its productivity has improved slightly over time coming down from 6.04 in 2004 to 5.95 in 2006.

Figure 21
Generation Productivity



3.3.3 Transmission-Distribution Indicators

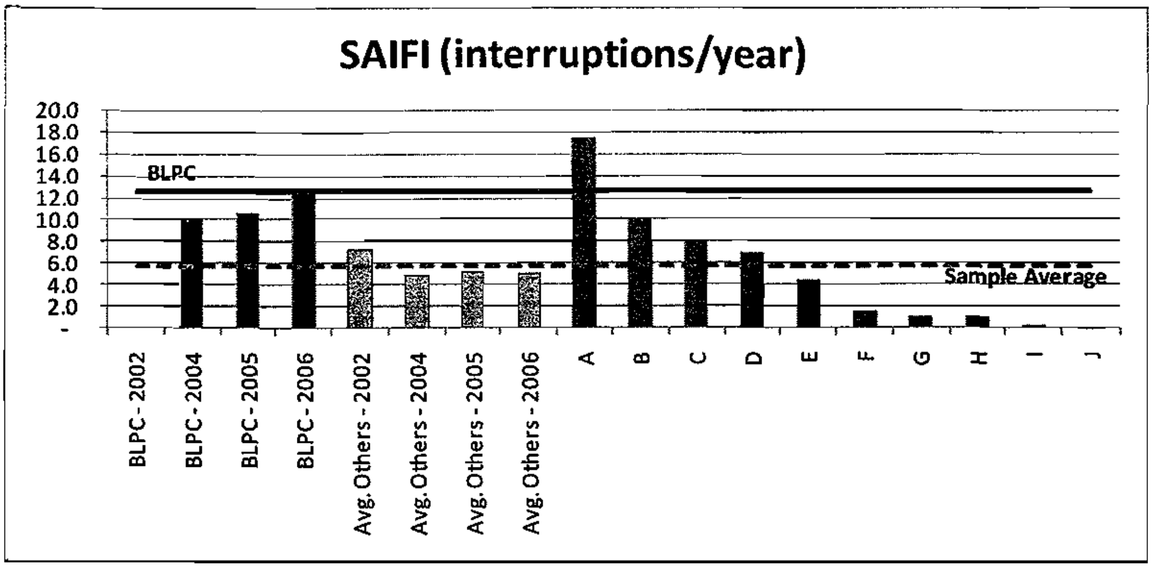
3.3.3.1 Network Reliability - SAIFI (TD.3) and SAIDI (TD.4)

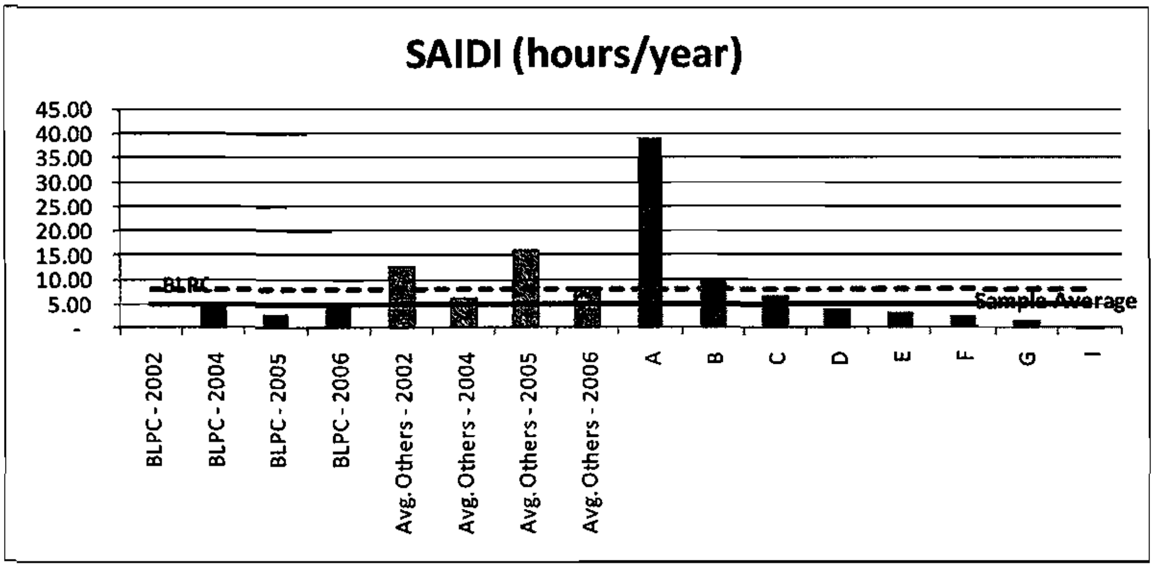
As for generation, reliability figures can be measured for Transmission and Distribution. The two indicators generally used are the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). SAIFI measures the frequency of interruptions experienced by the average customer. The higher the number, the more interruptions an average customer experiences. SAIDI is the counterpart of SAIFI and also takes into account the duration of the interruptions. Given that SAIFI is fixed (i.e. the number of interruptions is the same), a higher level for SAIDI implies that interruptions last longer on average. Even though it will not be technically feasible to achieve zero interruptions, utilities generally aim at lower SAIFI and SAIDI levels as this reflects a more reliable service towards customers.

The number of utilities reporting SAIFI and SAIDI is low as these indicators are more difficult and costly to measure. The average SAIFI for the sample is 5.7 interruptions/year and the

SAIDI is 7.95 hours. For BLPC, the SAIFI and SAIDI imply an average of 12.6 interruptions per year and an average interruption time of 4.9 hours per year. Compared to the region, there are relatively more interruptions for BLPC but the time required to solve the interruption *is shorter. Overall, as measured by SAIDI, the average interruption time for BLPC is still* better than the regional average.

Figure 22
SAIFI and SAIDI



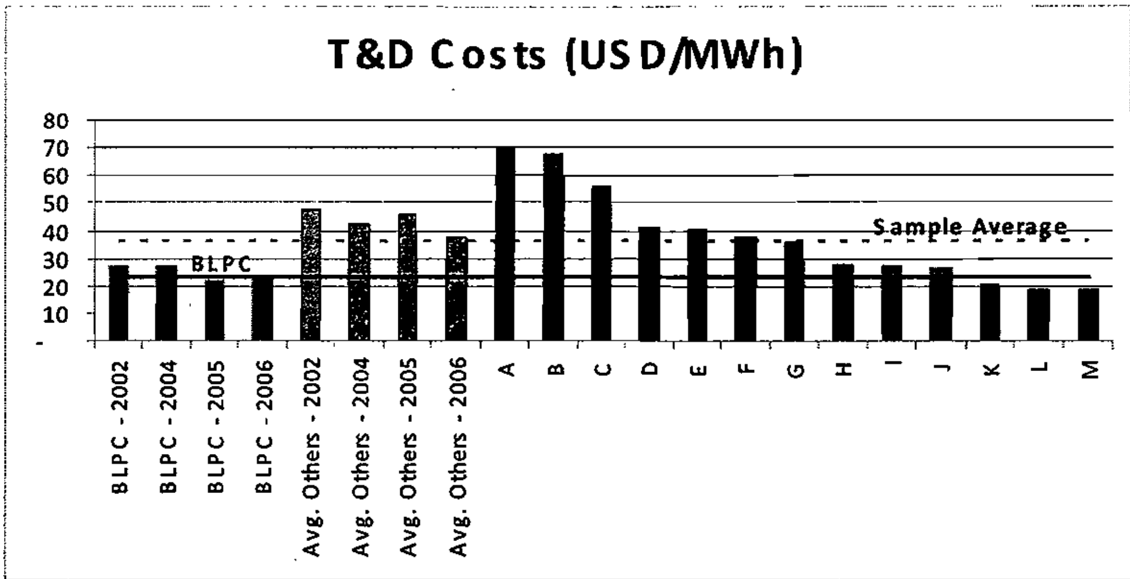


3.3.3.2 Transmission-Distribution Cost (TD.5)

The T&D cost indicator is defined as the total T&D related costs, divided by the total amount of electricity delivered. The average cost for the region is 36 USD/MWh (or 3.6 ct USD/kWh). This level has remained more or less stable in recent years as, unlike generation costs, T&D costs are less affected by fuel prices.

For BLPC, the T&D costs of 23 USD/MWh are less than average indicating a low cost level. This, again, can be caused by genuine higher efficiency and by the economies of scale.

Figure 23
Transmission-Distribution Costs



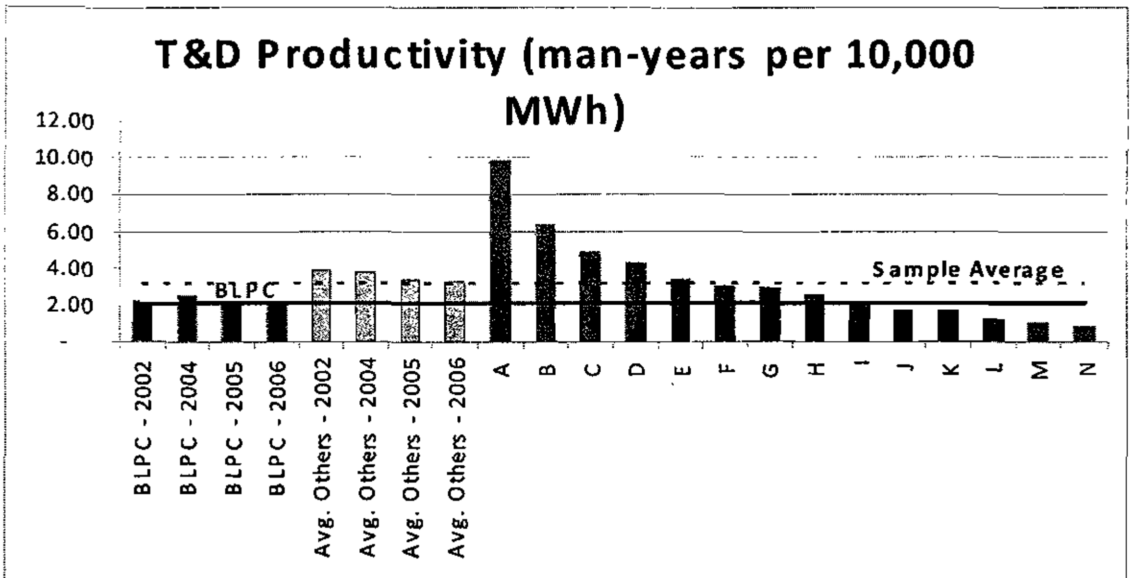
3.3.3.3 Transmission-Distribution Productivity (TD.6)

Productivity in transmission and distribution is defined as the number of man-years per 10,000 MWh of supplied electricity. A lower value for the indicator is desirable as this implies higher productivity i.e. less use of resources to supply.

The regional average value for transmission-distribution productivity was 3.16 man-years per 10,000 MWh. The indicator has decreased somewhat in recent years indicating an improvement in T&D productivity.

Productivity within BLPC is higher than the regional average with 2.11 man-years per 10,000 MWh. Performance for BLPC has remained high over time with some small fluctuations from year to year. BLPC has however consistently maintained a large distance from the region's average performance and outperformed each year to a significant degree.

Figure 24
Transmission-Distribution Productivity



3.3.4 Commercialization Indicators

3.3.4.1 Number of Complaints (CM.2)

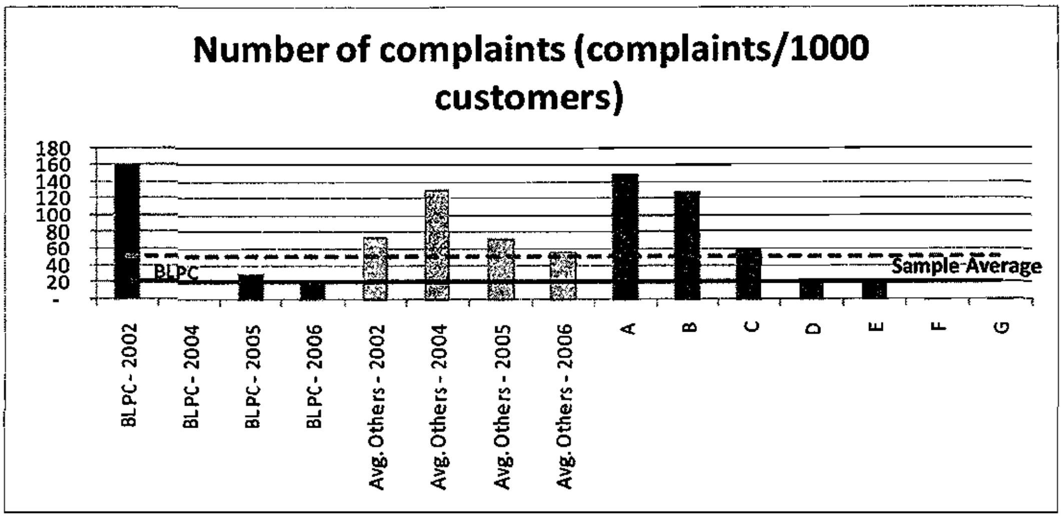
The number of complaints is normalized per 1000 customers. A higher number shows more complaints and associated with that, one can expect lower customer satisfaction.

The regional average number of complaints was 55 per thousand customers. We should note that the number of companies participating in this indicator is low due to not all companies having in place a complaint tracking and handling system.

In 2006, BLPC scored 19.9 complaints per 1000 customers which is lower than the regional average in that same year (55). The frequency of complaints in 2002 was quite high but this seems to have been successfully dealt with based on the significant reductions in 2005 and 2006.

KEMA

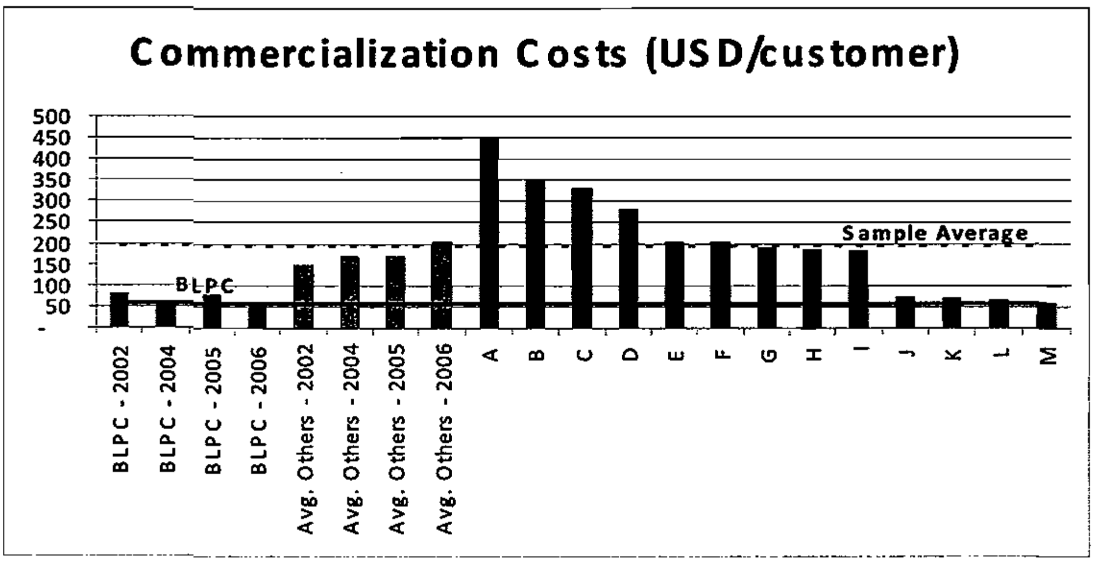
Figure 25
Complaints



3.3.4.2 Commercialization Cost (CM.3)

Commercialization costs are normalized per customer served. The average annual commercialization cost in the region was 193.1 USD/customer. BLPC has the lowest commercialization costs of the region in 2006 with 59 USD/customer. Cost levels have fluctuated somewhat between 56 and 79 USD/customer over time.

Figure 26
Commercialization Cost



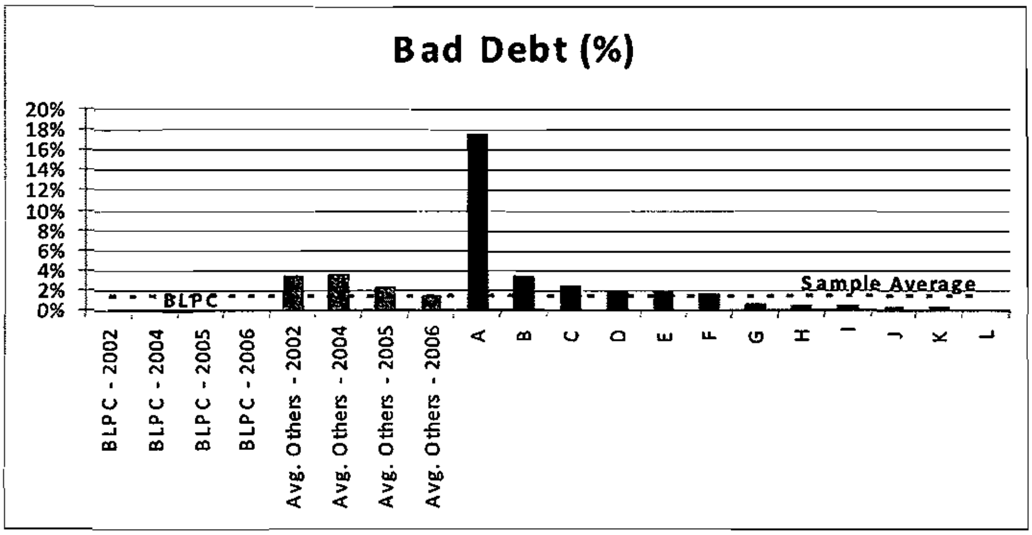
3.3.4.3 Bad Debt (CM.4)

The bad debt indicator considers the level of receivables not collected after 180 days in relation to the revenue. Lower bad debt levels are desirable as bad debts directly affect the bottom-line of the company.

The average bad debt in the region was 1.17% of operational revenue with a lowering trend as noticed in recent years. The average is however strongly influenced by one company with an exceptional bad-debt level. If this company is excluded the average would be equal to 1.3%.

BLPC has the lowest bad debt in the region at only 0.1% and is performing substantially better than its regional counterparts.

Figure 27
Bad Debt

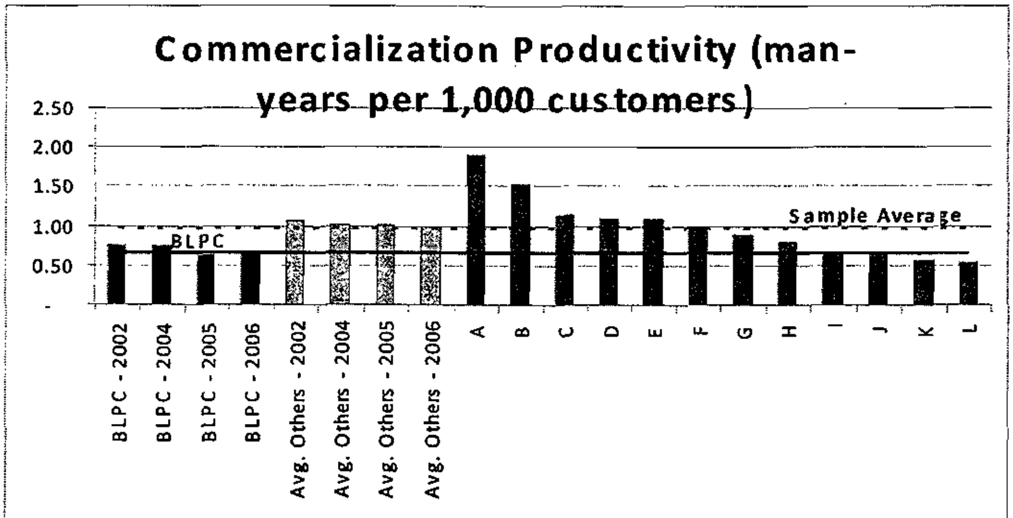


3.3.4.4 Commercial Productivity (CM.5)

Productivity in the area of commercialization is defined as the number of man-years active in this area per 1,000 customers served. Lower values indicate higher productivity levels.

For the region, the average commercial productivity was 0.97 man-years per 1,000 customers served. This number has remained stable over the last few years. For BLPC, the productivity is higher than the average and stands at 0.67 in 2006. The productivity has remained stable and increased slightly in the last few years.

Figure 28
Commercialization Productivity



4. International Comparison

4.1 BLPC as an Island System versus Mainland Systems

This section of the report compares the operating results of BLPC with performance indicators in other parts of the world, in order to assess the standing of BLPC against international practices. The consultant searched operating data of electric utilities in different world regions, the figures found and presented in this chapter correspond to averages of several utilities within wide geographical areas or to representative values of utilities in particular regions.

In order to present international "best practices" and compare with island utilities such as BLPC, the Consultant selected relevant performance indicators for which non-confidential information was available. It is necessary to take into account that international values are not always directly comparable with the results of Caribbean utilities due to differences in important factors like system and demand scale. the physical environment, the degree of economic development, population income, the structure and regulation of the power industry, the availability of energy resources, the production and distribution technologies used, the size of utilities in terms of capacity and load demand, the size and composition of markets served, the maturity of the utility industry and differences in technological development and labor markets.

The comparisons presented here have an illustrative purpose and do not pretend to offer definitive evaluations of the efficiency. Instead, they are aimed to provide useful data to help interpreting the operating profile of an island utility such as BLPC in the context of current best practices of companies engaged in the same activities and providing similar services around the world.

When looking into Benchmarking Information on Island Systems, such as the information in this Report featuring BLPC in a peer group of Caribbean utilities, but also when looking at information of other island systems worldwide, we can identify that in the field of power generation small island systems cannot keep up with the efficiency of mainland systems for very obvious reasons, but at the same time it can be seen that in the field of T&D such as T&D costs and losses the results of island systems can meet the results of mainland utilities.

Whether the scale is large or small, technical losses depend on the way the grids are designed, operated and maintained to serve a geographic area with industrial, commercial and residential clients. Non-technical losses occur independently from any size of the electric utility. And even when looking at the T&D costs per MWh BLPC is able to remain below the average of a large peer group of mainland utilities, although it could be expected that in this field less economy of scale would influence the cost level. It is shown however that an island utility at BLPC's size can already compete with mainland utilities when it comes to T&D costs. Of course BLPC has the advantage of a relatively high load per customer compared with many others in the Caribbean peer group and also the population density in Barbados is highest of the peer group's islands. On the SAIDI and SAIFI figures (interruption duration and frequency) the following can be identified:

- On SAIFI. (interruption frequency) BLPC's performance Is at the average when looking at worldwide figures, including figures of mainland utilities, which indicates that BLPC's practices in order to avoid outages are working out reasonably well in the field of international utilities;
- On SAIDI we see a higher outage duration, which surely has something to do with the fact that there are no interconnections with other systems existing.

In the field of Generation there will always be a distance between small island systems and the mainland systems for the following reasons:

- The island systems have no interconnections and need to keep up a higher reserves margin
- Island power systems, due to their relatively small size, face lower economies of scale and are constrained in their choice of fuel
- Costs of fuel are higher because of the smaller volumes needed and because the usage of cheaper fuels like Natural Gas, Coal, Nuclear, is only feasible if applied on larger scale. Large Caribbean islands for example can afford the usage of LNG and coal.

For island systems it is important to target on the most optimal fuel mix, but the volatility of fuel prices makes it difficult to decide for the right choices.
Given the constraints of Island Systems which keep them at a distance of mainland systems, it is obvious that tariffs of island systems are also higher than of mainland systems. This is illustrated in the following sections where the level of tariffs will also be compared with mainland systems. Still BLPC managed to have practically the lowest tariffs within the Caribbean peer group if we don't count the very low rates of an island utility which have been subsidized.

When it comes to the question where BLPC stands, we can identify that:

- BLPC performs as (one of) the best when looking at all the performance indicators as calculated for the peer group of Caribbean utilities;
- BLPC can compete in the field of T&D with the average performance worldwide and with respect to system losses BLPC even belongs to the world's best in class;

Before entering into the next chapters, showing BLPC's performance against International Practices, it should be mentioned – when looking at where BLPC stands compared with International Practices – that BLPC's Labor Productivity, being one of the best in the Caribbean, is equal to the average Labor Productivity in the USA. This indicates better performance by BLPC to still reach an equal productivity level, working in a production park and with T&D networks of much smaller scales and as such asking for more labor per "unit" (for "unit" one can think of generation units, infrastructure/lines per customer, etc).

4.2 International Practices

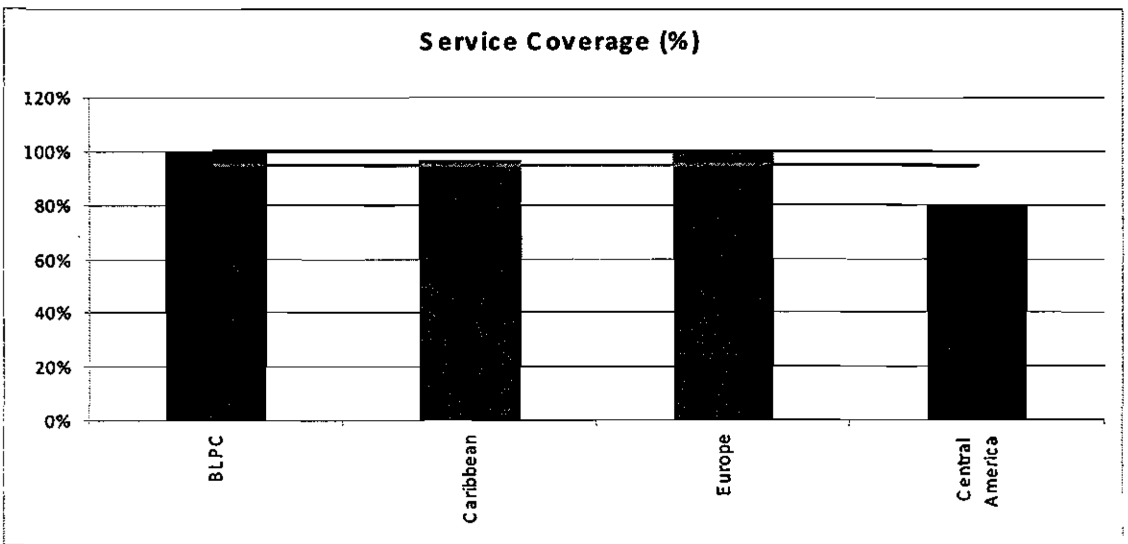
The comparisons presented here correspond to the year 2006 both for BLPC as for the other countries. Note that as international data was not always available for each utility, the comparison sample will vary per indicator.

4.2.1 General Indicators

4.2.1.1 Service Coverage

For countries in Europe and other developed countries service coverage is practically 100%; in less developed countries there are differences between the urban areas with relative high coverage and the rural areas with lower coverage. In the following figure, Central America corresponds to the average of six countries (Costa Rica, Panama, Nicaragua, Honduras, El Salvador and Guatemala). As was previously observed, Barbados has a service coverage rate of 100% which is in line with best-practice.

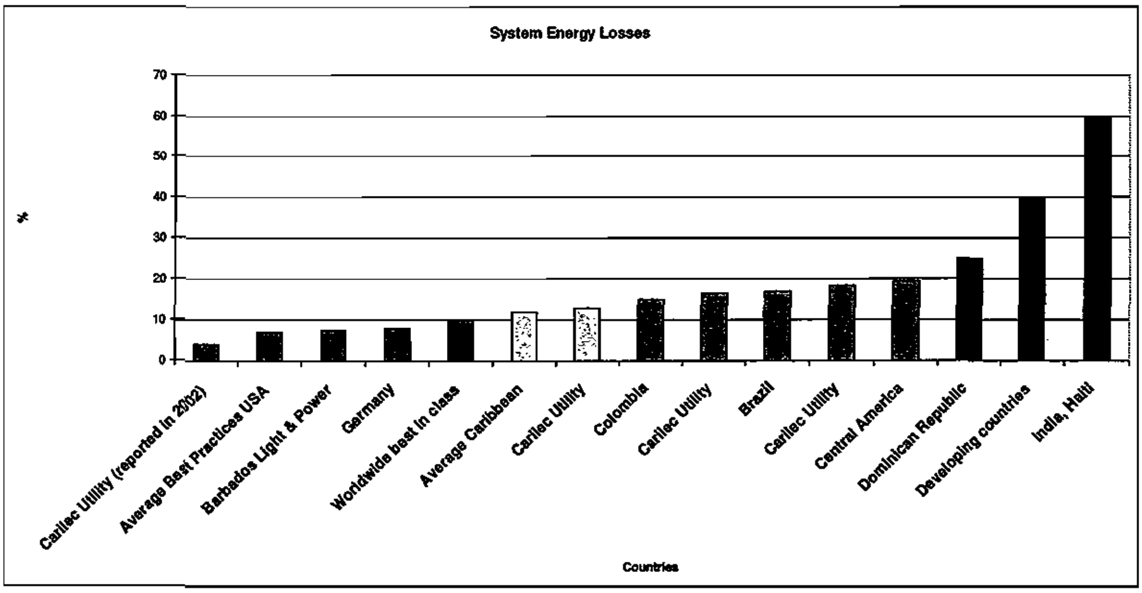
Figure 29
Service Coverage (International)



4.2.1.2 System Energy Losses

In figure 36 system energy losses are shown for different countries worldwide and the utilities marked green are best in class (< 10%). With system losses of 7.5% BLPC belongs to the best in class. The average of losses in the USA is 7% but it must be noted that losses of USA utilities include plant losses; losses of Caribbean region are net of plant losses. The USA figure is an average of 14 utilities. BLPC's performance is between that in the US and is much lower than the Caribbean average. Still the Caribbean average is relatively good compared with other countries in the world, although some of the Caribbean utilities as indicated anonymous really need to develop or strengthen their loss reduction programs.

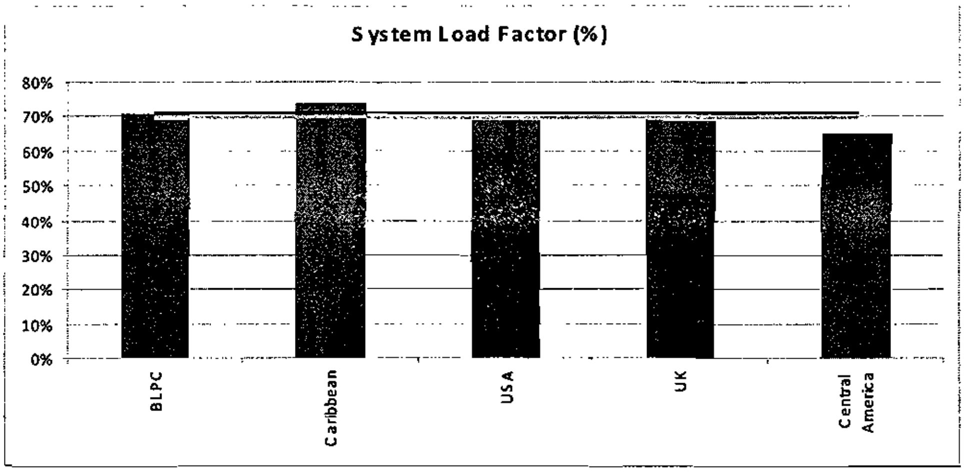
Figure 30
System Losses (International)



4.2.1.3 System Load Factor

The UK figure is an average of 40 utilities; USA is an average of 15 utilities; Central America corresponds to the average of the six countries (Costa Rica, Panama, Nicaragua, Honduras, El Salvador and Guatemala). As can be observed, BLPC's load factor is comparable to those in the US and the UK.

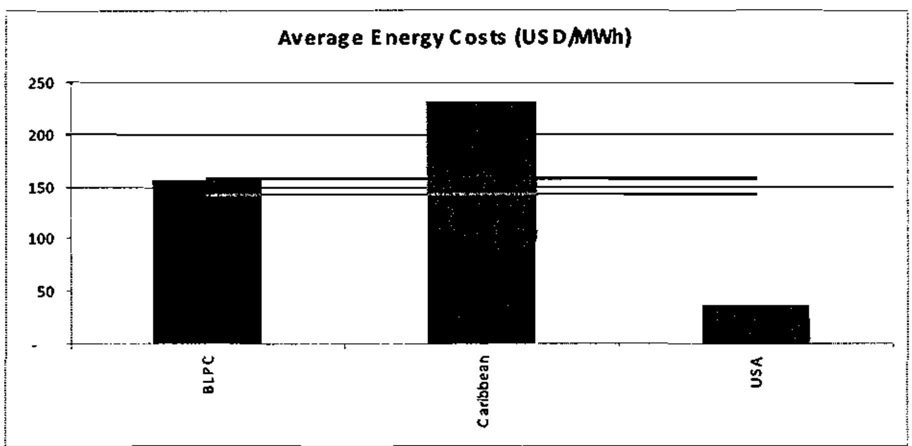
Figure 31
Load Factor (International)



4.2.1.4 Average Energy Cost

BLPC's energy costs are among the lowest in the Caribbean but still significantly higher than in the US. The explanation for this can be found in the fact that, due to the relatively small size, generation is constrained to a few technologies such as diesel engines, although BLPC's production mix also consists of steam turbines and gas turbines. In the US, where demand is much higher, use can be made of technologies such as nuclear power, natural gas and coal, which have much lower costs.

Figure 32
Energy Cost (International)



4.2.1.5 Electricity Rates

The following figures show a comparison of international electricitt tariffs as compared to tariffs in Barbados. Note that BLPC's tariffs for domestic customers allow for 10% prompt payment discount and include 15% VAT. Commercial and Industrial bills exclude VAT as this can be reclaimed as "Input VAT".

The higher energy costs in the region, and in Barbados, are reflected in higher rates for customers. We should note that a strict comparison of rates should be performed with caution as observed differences also result from differences in regulatory policy. For example, as can be seen from the Figure, rates in India and South-East Asia are significantly lower. This, however, is the combined result of a deliberate government policy and the availability of state subsidies. The impact of limited scale faced by island economies can be demonstrated for example by the fact that electricity rates in Hawaii are comparable to those in the Caribbean region. Still, rates in Barbados are lower than the region as well as lower than those in Hawaii.

Figure 33
Residential Rates (International)

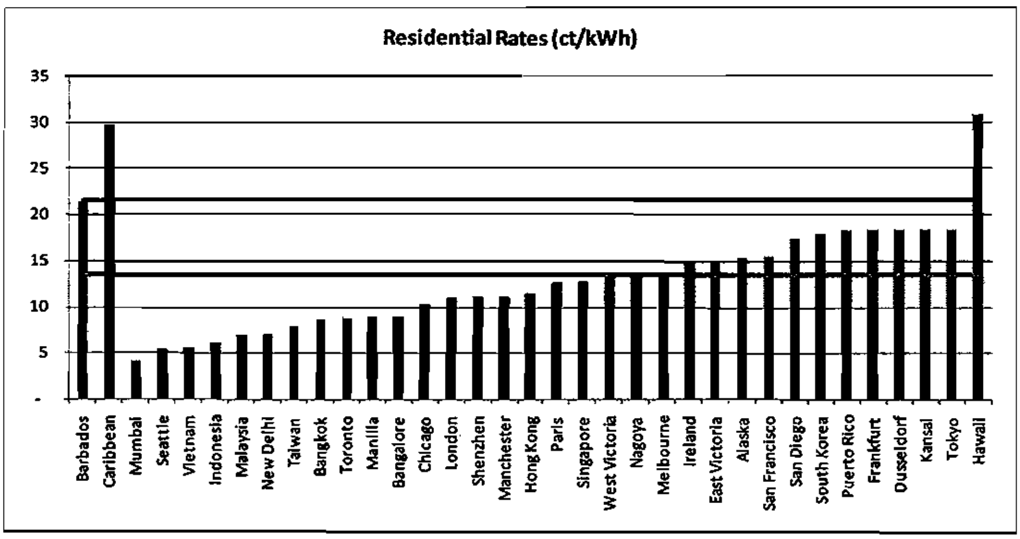


Figure 34
Commercial Rates (International)

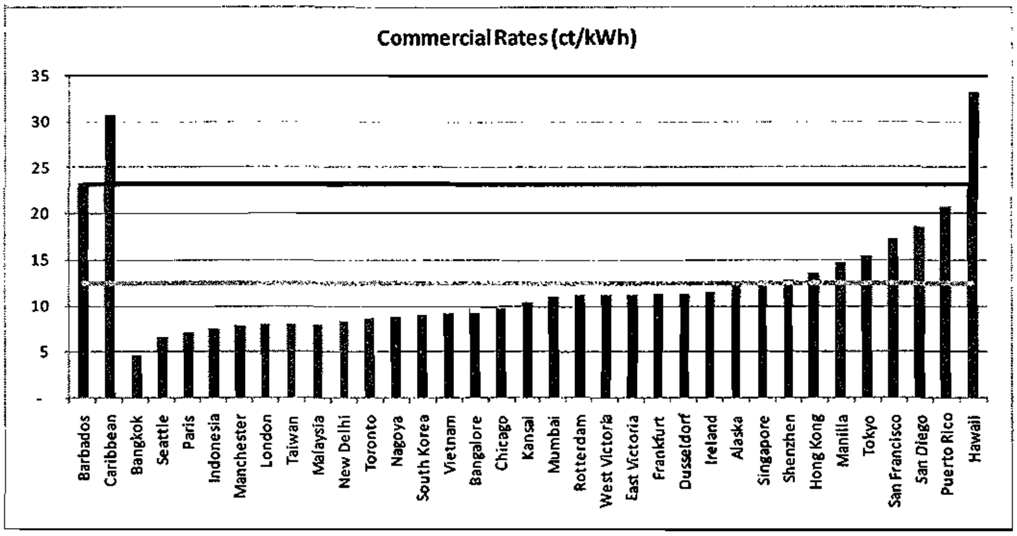
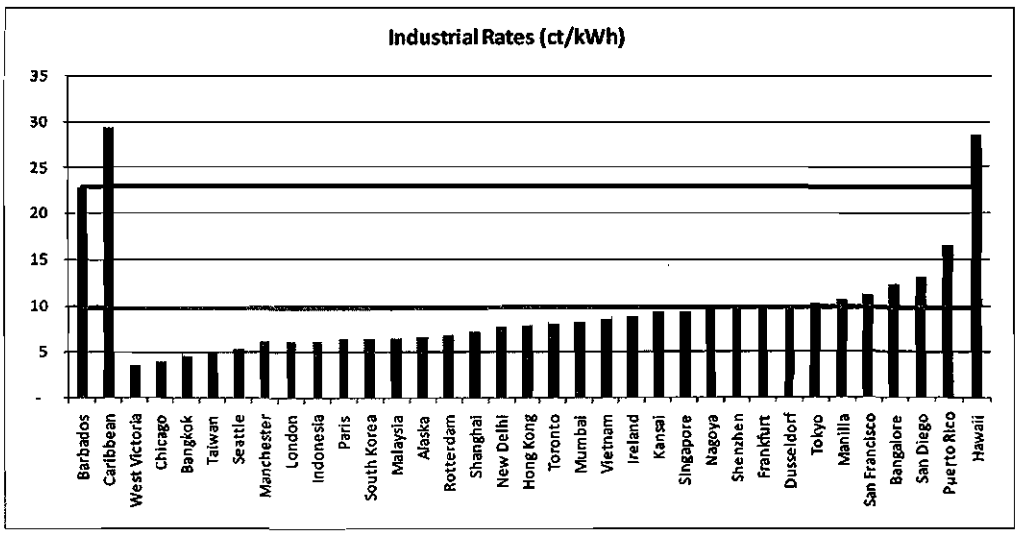


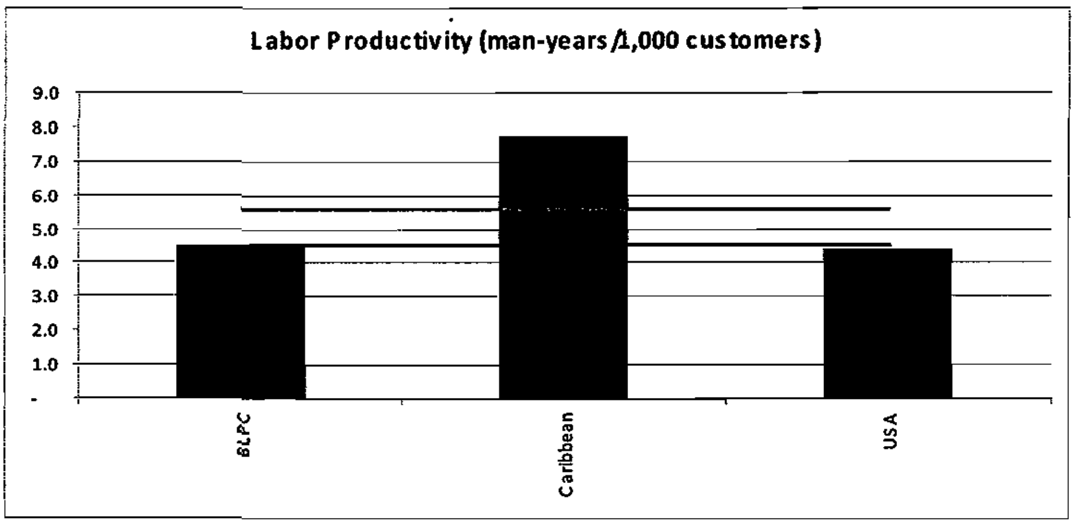
Figure 35
Industrial Rates (International)



4.2.1.6 Labor Productivity

The previous comparisons considered the energy costs and the rates. As mentioned before, these figures are strongly influenced by the relative disadvantage in the Caribbean with respect to fuel costs. Considering labor productivity is therefore a better indicator of the true efficiency of the utility. The following Figure shows that BLPC's productivity is more or less equal to the average productivity in the US. Given the fact that US utilities have a much larger scale, this indicates better performance by BLPC to still reach an equal productivity level, working in a production park and with T&D networks of much smaller scales and as such asking for more labor per "unit" (for "unit" one can think of generation units, infrastructure/lines per customer, etc). As observed earlier, BLPC's productivity is also significantly better than the regional average.

Figure 36
Labor Productivity (International)



4.2.2 Generation Indicators

4.2.2.1 Generation Reserve Margin

Central America corresponds to the average of six countries (Costa Rica, Panama, Nicaragua, Honduras, El Salvador and Guatemala). Figures shown are system-wide reserves. The generation reserve margin for BLPC is somewhat higher which is due to the smaller scale and therefore a need to maintain more reserve capacity.

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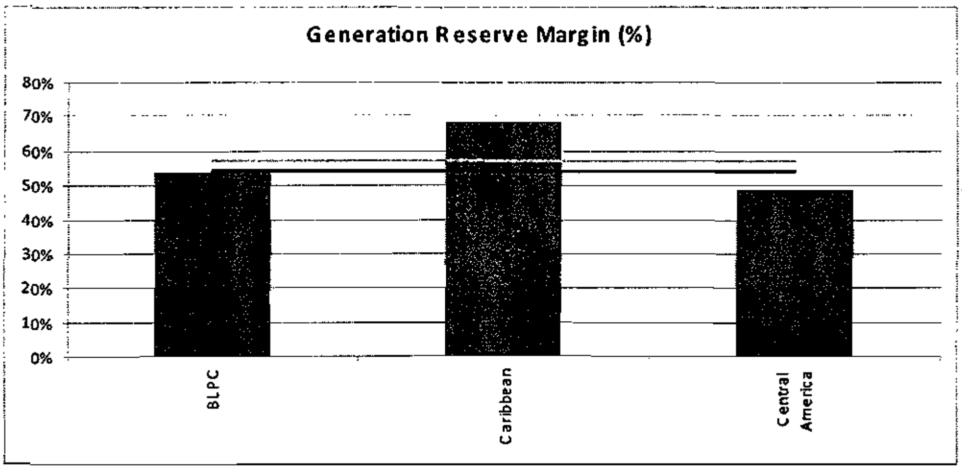
Figure 37
Generation Reserves (International)

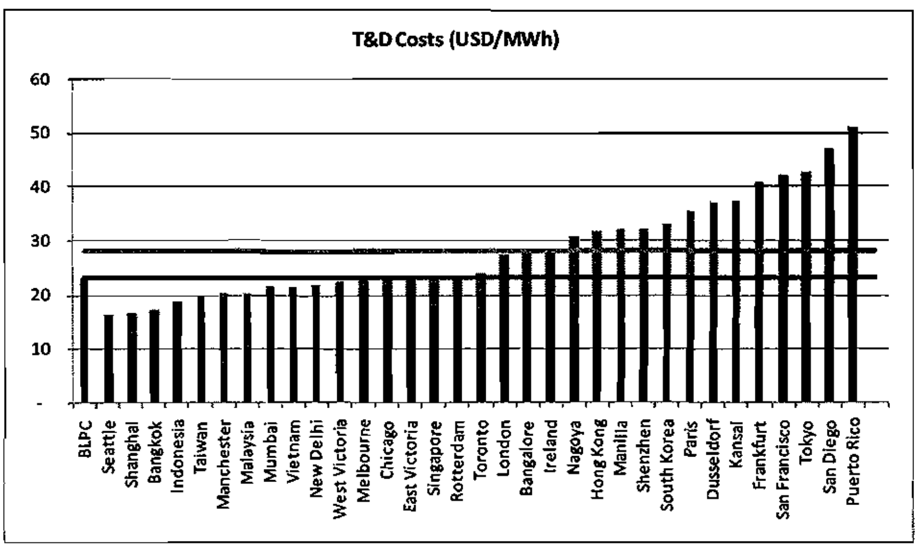


4.2.3 Transmission–Distribution Indicators

4.2.3.1 T&D Costs

T&D costs only relate to the network part of the utility, which is much less sensitive to changes in fuel prices. This effect can also be observed in the following Figure. BLPC's T&D costs are comparable to the costs observed in some European and Asian countries and are lower than the average of the international sample. This is in line with the previous observation of BLPC's high productivity levels.

Figure 38
T&D Costs (International)



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4.2.3.2 Reliability Indices SAIFI and SAIDI

The following figures show international comparisons of the SAIFI and SAIDI indicators. BLPC's SAIFI and SAIDI figures are higher than the international counterparts.

Figure 39
SAIFI (International)

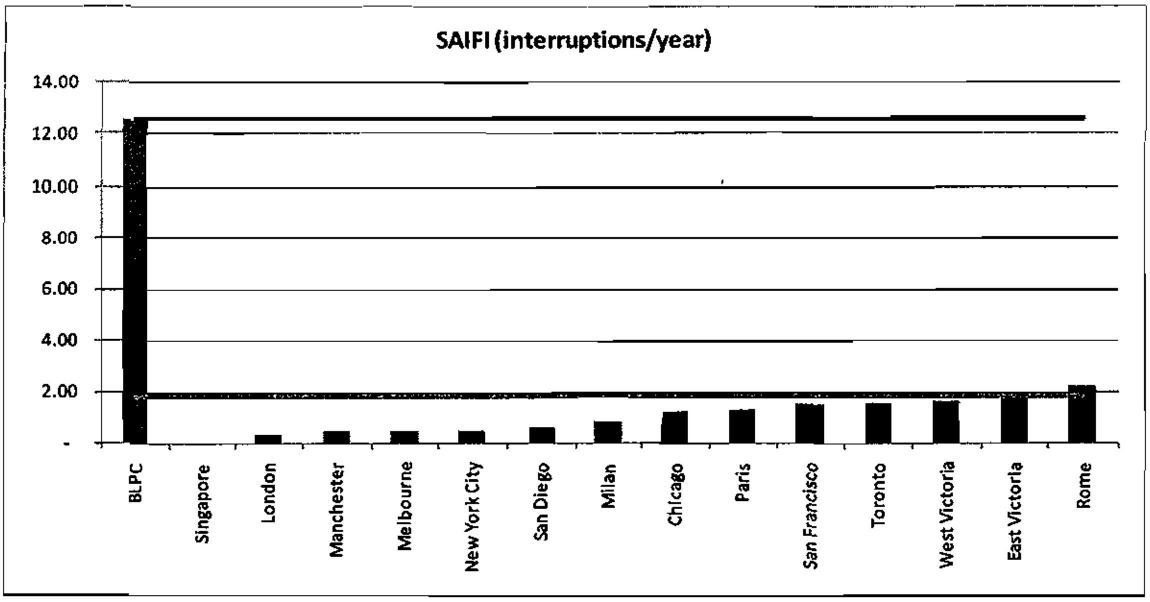
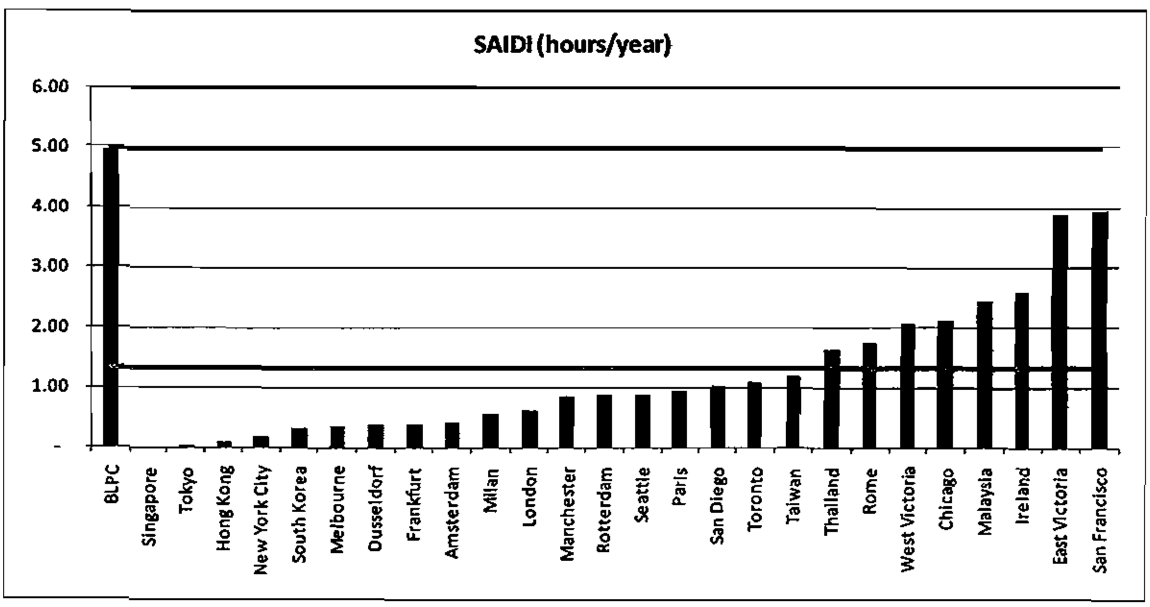


Figure 40
SAIDI (International)



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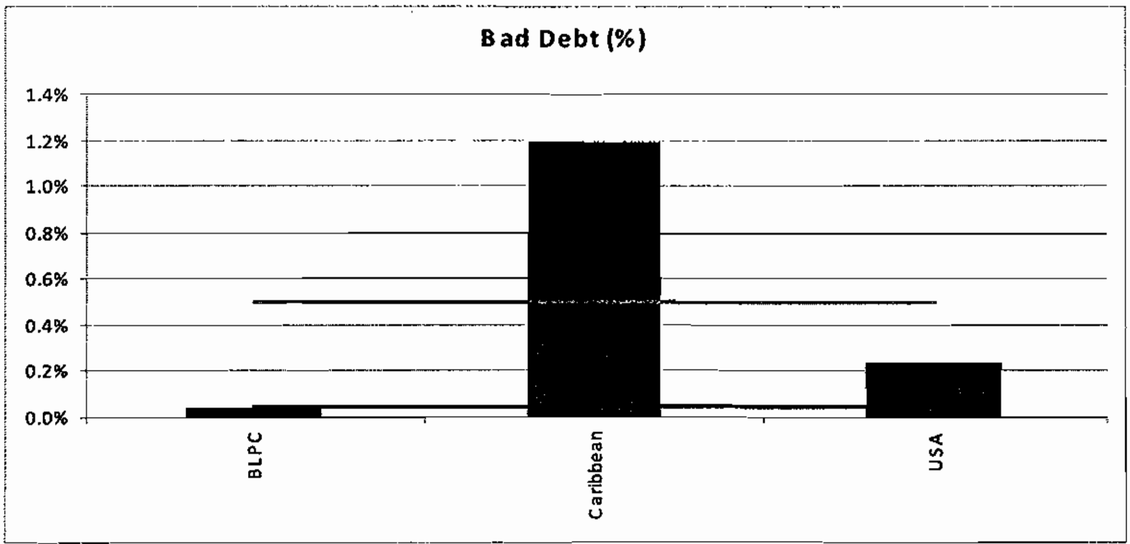
4.2.4 Commercialization Indicators

4.2.4.1 Bad Debt

The level of bad debt for BLPC was already shown to be very low. When put in the international context (US average of 13 utilities) it can be seen that this is still the case.

Figure 41
Bad Debt (International)



5. Conclusions and Recommendations

5.1 Overall Benchmarking Conclusions

This report presented the results of the performance benchmarking of BLPC versus other Caribbean utilities as well as different international mainland utilities. The comparisons were made for the year 2006 within the limitations of the quality of the information supplied.

The main observation of the comparisons is that relative to its regional peers, BLPC is performing as one of the best. Apart from one indicator (plant energy consumption), BLPC always scores better than the average and is located within the better performing quadrant of the sample. The better performance of BLPC can be explained by (1) exogenous factors, and by (2) higher productivity levels within BLPC.

Exogenous factors include the relatively high demand levels in Barbados and perhaps also the higher customer density. This provides some economies of scale and therefore relatively lower costs for BLPC. On the other hand, the comparisons also show that BLPC has one of the higher productivity levels in the region and is comparable to average productivity in the US. This factor is likely to have a very positive impact on BLPC's technical and cost performance.

As already outlined in section 4.2: "BLPC as an Island System versus Mainland Systems", the major difference between BLPC and mainland systems is because of the higher generation costs, including higher fuel costs. In the field of T&D we have seen BLPC performing on a good level compared with mainland systems and when it comes to important indicators on T&D costs per MWh, system energy losses and the interruption frequency, BLPC can compete with the different mainland utilities as shown in the previous chapter. Interruption durations tend to be longer, which can be explained by the lack of interconnections with other systems.

When focusing on Generation Costs and at the production mix as well as the corresponding fuel mix of BLPC's power production assets – steam turbines, low speed diesels, gas turbines and some waste heat turbines – it shows that with this mix, most likely combined with favorable fuel purchasing contracts, BLPC can manage to be one of the most efficient generators of electricity in a field of island systems. It is also remarkable that the increase of generation costs during the years 2002 through 2006 has been more moderate than for the other utilities in the peer group.

Only in very large islands, where it is also feasible to apply fuels like LNG or coal, or in islands with abundant hydro possibilities, substantially better generation costs can be reached. On generation options BLPC is also exploring the option of wind power, which is an option with intermittent power supply, but with a price per kWh that has become very competitive the more the oil prices have increased. At the same time wind power contributes to a reduction of greenhouse gasses.

Furthermore it is surely noteworthy that the overall labor productivity of BLPC is outstanding, even if we take outsourced works into account, which are on an average level compared to its relatively low number of Caribbean peers that have reported the kind of outsourced work and the cost of it. The total of works as outsourced by BLPC amounts to around US$ 2.3 million. Similar utilities with somewhat equal loads and numbers of customers show figures for outsourced work like US$ 1.9 million, US$ 2.7 million and US$ 3.2 million, but some of them also included consulting orders and costs for projects of new infrastructure. In the end the figures as reported are not purely comparing apples with apples, but the results can be considered reasonably close to reality.

5.2 Recommendations per Performance Indicator

When looking at the trends during the period 2002 – 2006 it can be observed that in general BLPC has kept its good performance rather constant during the years. In the table below we have summarized all results for 2006 and the trends in the years from 2002 through 2006 per Performance Indicator. Furthermore recommendations are given per Performance Indicator where appropriate.

Performance Indicator	BLPC's Performance	Trend 2002 – 2006	Recommendations
Service Coverage	100% coverage among 8 other utilities with max. coverage	100% through the years	
System Energy Losses	With 7.5% sharing the # 1 position in 2006.	Rather stable through the years. Best performance was in 2005, with 7.2%	Determine technical losses as close as possible, in order to find out the level of non-technical losses, which enables better monitoring and control of losses.
System Load Factor	On the average of the Caribbean with 71%. Indicates a good utilization of the assets.	Stable through the years.	
Average Energy Costs	Second best with $ 157.17 per MWh	Upwards trend because of increasing fuel prices. Still BLPC's increase is more moderate than at other	In case fuel prices will increase further in the coming years (after the current drop of oil prices

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Performance Indicator	BLPC's Performance	Trend 2002 – 2006	Recommendations
		utilities.	during the financial crisis of Oct 2008), serious studies must be undertaken on the fuel mix, fuel diversification and renewables, in order to also keep future costs as low as possible.
Rates (Residential, Commercial, Industrial)	Second best in all categories with few exceptions where BLPC ends third best. Subsidized utilities have not been taken into account.	Of course rates have increased year by year but at a lower pace than at most of the utilities.	
Operational Profit Margin	With 6.4% below the average of 8.1%.	Downward trend in the past 3 years.	Review tariffs in relation to financial performance
Return on Assets	With 4.1% below the average of 7.3%	Downward trend, ROA was 6.7% in 2002 and 7.1 % in 2004.	Review tariffs in relation to financial performance
Debt Level	With 19.2% the lowest debt level except for one utility	Between 14% (2002) and 24.6% (2004). Rather low debt level during the years.	
Labor Productivity	With 4.51% in the top 4. Average level is 7.51%	Quite constant through the years.	Analyze the impact and efficiency of outsourced works.
Safety incident rate	1.75 safety incidents per 100 employees, which is below the average of 2.91	Higher in 2002 and 2004, but only in 2004 somewhat above the average.	EHS Department to evaluate and monitor safety incidents and to look for any appropriate safety improvements
Generation	54.1% which is below the	Rather constant, only	

Performance Indicator	BLPC's Performance	Trend 2002 – 2006	Recommendations
reserves margin	average of 68.7%. Looks like BLPC is balancing at the right reserves margin.	in 2004 the margin was somewhat lower: 49.4%	
Generation availability	In the top 3 with 87.6% (average is 78.8%).	High availability through the years.	Evaluate availability issues continuously and look for further improvement.
Plant energy consumption	4.3% which is somewhat higher than the average of 4.1%	Plant energy consumption is increasing per year. Lowest was 3.5% in 2004	Evaluate the plant consumption and take measures to reduce the plant consumption.
Utilization factor	48.1% while the average is 39.7%.	Rather constant.	
Generation non-served energy	0.14 o/oo which is quite good and below the average of 0.715 o/oo	Rather constant	
Fuel costs	Fuel costs 95.77 US$/MWh, average is 126.78. BLPC in the top 4.	From 2002 to 2006 the increase is "only" 62%, while most utilities show higher increases up to 300%. Only one utility has a lower increase.	Study possibilities of fuel supply and fuel diversification in the long run, including renewables, in order to anticipate on rising fuel prices.
Generation costs (excl. fuel costs)	BLPC again in the top 4: 130.2 US$/MWh against an average of 175 US$/MWh	From 2002 to 2006 these costs increased with 54%. There is a group of 7 utilities with similar or somewhat lower growth, the others' generation costs has grown faster.	Study the most efficient production mix of the future, anticipating on fuel price developments and technological developments.
Generation Productivity	BLPC in the top 3 with 5.95 man-years/ 10 MW. The average is 11.53 man-years/ 10 MW.	Quite constant through the years.	Review the impact and efficiency of outsourced works.

Performance Indicator	BLPC's Performance	Trend 2002 – 2006	Recommendations
Energy Grid Losses	Only very few utilities reported energy grid losses, BLPC only reported these losses in 2002 and 2004. This indicator has not been included in section 3.3.3	From what BLPC reported in 2002 and 2004 it looks like energy grid losses are almost equal to Energy System Losses, which means that hardly any non-technical losses occur at BLPC.	Calculate energy grid losses as close as possible, since no figures seem to be available for 2005 and 2006.
T&D non-served energy	Again too little data has been made available. BLPC's level of 0.37 o/oo is low against the average of 0.6 o/oo (average of only 7 participants).	Although a little bit fluctuating up and down, the overall score is rather constant.	
SAIFI and SAIDI	SAIFI is higher than the regional average but SAIDI is lower.	SAIFI is slightly increasing but SAIDI is more or less stable.	
T&D Costs	A good score for BLPC (23.06 US$/MWh) even quite good in the International Comparison The Caribbean average is US$ 35.44 / MWh	T&D costs went down with 15% since 2002 and were even lower (21.58) in 2005.	
T&D productivity	2.11 man-years / 10,000 MWh, average is 3.38	T&D productivity remained rather constant from 2002-2006, with little peaks up and down.	Look at the impact and efficiency of outsourced works.
Non-technical losses	No participant reported non-technical losses. Also in the past years only a few reported these losses.	BLPC did not report non-technical losses through the years. Since the reported technical losses are almost equal to the total losses it is assumed that BLPC	Start developing a methodology for identification of non-technical loss causes, if the calculations of system losses and technical losses

Performance Indicator	BLPC's Performance	Trend 2002 – 2006	Recommendations
		has hardly any non-technical losses.	also point at non-technical loss causes
Number of complaints	BLPC did not report complaints. Only 7 participants did (the average is 55.34 *complaints per 1,000* customers)	BLPC reported complaints in 2002 (159.79) and 2005 (30.10). *2002 must have been* an exceptional year.	Set up a methodology for reporting complaints and *analyze the* subjects of complaints.
Commercialization Costs	58.52 US$ per customer which is the lowest score (average is US$ 193.1).	Downward trend (23% lower than in 2002).	
Bad debt	*BLPC has the lowest* score with 0.05%. The average is 2.09%	*Very low through the* years (almost zero in 2002 and 2004)	*Although BLPC is* doing very good, keep monitoring and stay in control of the bad debt level
Commercialization productivity	0.67 man-years per 1,000 customers, average is 1.104	Downward trend through the years (10% lower than in 2002).	Figure is quite low, but still look at the impact and efficiency of outsourced works.

5.3 Final Observations

KEMA would like to conclude this chapter of conclusions and recommendations with the following remarks.

Within the peer group of Caribbean utilities it has been proven through the past 4 years that BLPC is performing as one of the best, with very little exceptions of less *performance. In the International Comparison* it has been found out that BLPC can compete with mainland utilities on T&D issues, Labor Productivity, and some more indicators.

When it comes to identification of "best practices" for island systems we can consider the best performing utilities in the Benchmark Study as representing Best Practices in the peer group of Caribbean utilities. A broader group of island systems should be examined in order to generally determine what would be Best Practices for island systems, looking at the different performance indicators such as generation, T&D, organizational, commercialization, financial performance.

It would be interesting for BLPC to start exploring worldwide best practices of island systems as well as its frontiers of excellence, being an island system. BLPC would like to look now where it stands among other islands in the world, such as European and Asian islands, in order to find out if BLPC will reach high rankings as well in a much broader peer group. *At the same time a broader peer group may give* BLPC *more comparison* materials and more clues on possibilities for further improvements.

In particular – knowing that BLPC is already performing for a greater part at a "mainland-level" in T&D - it should be explored what ultimate level of generation efficiency could be reached, higher than BLPC's current generation efficiency, and still at investment levels and O&M costs that will not affect the final efficiency outcomes negatively.

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Annex 1

Performance Indicators

Table A1-1
General Indicators Definition

<table>
<tr><th colspan="2">GENERAL INDICATORS</th></tr>
<tr><th>Indicator</th><th>Definition</th></tr>
<tr><td colspan="2">Technical</td></tr>
<tr><td rowspan="2">Service Coverage (%)</td><td>$$\frac{\textit{Population with electricity service}}{\textit{Total population}} \times 100$$</td></tr>
<tr><td>Shows the percentage of users within the area served by the Utility with electricity service. It is a measure of the overall efficacy of utility service.</td></tr>
<tr><td rowspan="2">System Energy Losses (%)</td><td>$$\frac{\textit{Net energy entering the system} - \textit{Total energy sold}}{\textit{Net energy entering the system}} \times 100$$</td></tr>
<tr><td>Net energy entering the system = net energy generated + energy purchased
Shows total system energy losses as a percentage of the net energy entering the system. It is a measure of the overall technical efficiency of utility service.</td></tr>
<tr><td rowspan="2">System Load Factor (%)</td><td>$$\frac{\textit{Net energy entering the system (MWh)}}{\textit{Maximun system demand (MW)} \times \textit{8760 hours}} \times 100$$</td></tr>
<tr><td>Shows the load factor of the system. It is a measure of utilization of system capacity. The maximum system demand is the annual system peak load.</td></tr>
<tr><td colspan="2">Economical</td></tr>
<tr><td rowspan="2">Average Energy Cost ($/MWh)</td><td>$$\frac{\textit{Total annual costs (\$)}}{\textit{Gross energy entering the system (MWh)}}$$</td></tr>
<tr><td>Gross energy entering the system = gross energy generated + energy purchased
Shows the average system cost of energy (including losses). It measures cost effectiveness of utility service.</td></tr>
<tr><td rowspan="2">Customer Service Rates ($)</td><td><i>End-Use Electricity Rates ($)</td></tr>
<tr><td>Final service rates charged to end users for specific amounts of consumption. It shows how much the service costs to consumers.</td></tr>
</table>

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GENERAL INDICATORS	
Indicator	**Definition**
	Financial
Operational Profit Margin (%)	$\frac{\textit{Net Income (\$)}}{\textit{Operational Revenue (\$)}} \times 100$
	Shows profit margin from operations. It is an indicator of the profitability of utility operations.
ROA Return on Assets (%)	$\frac{\textit{Net Income (\$)}}{\textit{Assets Value (\$)}} \times 100$
	Shows the rate of return on utility's assets. It measures how effectively assets are used to generate a return on investment. Only non current assets are considered.
Debt Level (%)	$\frac{\textit{Long Term Debt (\$)}}{\textit{Assets Value (\$)}} \times 100$
	Shows the level of indebtedness of the company. It is a measure of financial risk.
	Organizational
Labor Productivity (man-years/1,000 costumers)	$\frac{\textit{FTE of staff (man – years)}}{\textit{Total number of customers served / 1,000}}$
	Shows staff utilization per 1,000 customers served; FTE stands for full-time equivalent employees. It is a measure of how effective is the organization.
Safety incident rate (# incidents/100 employees)	$\frac{\textit{Number of work incidents}}{\textit{Total number of employees / 100}}$
	Shows the rate of occupational incidents per hundred employees. It is an indicator of occupational safety.

Table A1-2
Generation Indicators Definition

GENERATION INDICATORS	
Indicator	**Definition**
	Technical
Generation Reserves Margin (%)	$\frac{\textit{System installed capacity - System peak load}}{\textit{System peak load}}$
	Shows the margin of generation reserves as a percentage of system peak load. It measures the long-term adequacy of generating capacity to supply load.

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GENERATION INDICATORS	
Indicator	**Definition**
System Equivalent Availability (%)	$$\frac{\sum \text{Unit rating (MW) x available hours}}{\text{System installed capacity (MW) x 8760 hours}} \times 100$$
	Shows the availability of system capacity accounting for forced and planned outages. It is a measure of the reliability of generation equipment.
Plant Energy Consumption (%)	$$\frac{\text{Gross energy generated} - \text{Net energy generated}}{\text{Gross energy generated}} \times 100$$
	Shows internal consumption of energy in generation plants as a percentage of gross generation. It is an indicator of plant generation efficiency.
Utilization Factor (%)	$$\frac{\text{Gross energy generated (MWh)}}{\text{System installed capacity (MW) x 8760 hours}} \times 100$$
	Shows the capacity utilization factor for the system. It measures how much of the generating capacity of the system is actually used.
Generation Non-Served Energy (‰)	$$\frac{\text{Non served energy}}{\text{Total energy delivered + Non served energy}} \times 1000$$
	Measures energy not supplied due to generation outages. It is an indicator of generation service reliability.
Economical	
Fuel Cost ($/MWh)	$$\frac{\text{Total fuel costs (\$)}}{\text{Energy generated by thermal plants (MWh)}}$$
	Average cost of the fuel component per thermal MWh generated. It shows the impact of fuel costs on generation costs.
Generation Cost ($/MWh)	$$\frac{\text{Total generation costs (\$)}}{\text{Total gross energy generated (MWh)}}$$
	Average cost per MWh generated including capital costs. It measures cost effectiveness of generation activities.
Organizational	
Generation Productivity (man-years/10 MW)	$$\frac{\text{FTE of generation staff (man - years)}}{\text{System installed capacity (MW) / 10}}$$
	Shows staff utilization per 10 MW installed. It is a measure of productivity.

Table A1-3
Transmission–Distribution Indicators Definition

TRANSMISSION-DISTRIBUTION INDICATORS	
Indicator	**Definition**
	Technical
Energy Grid Losses (%)	$\frac{\textit{Entering energy} - \textit{Delivered energy}}{\textit{Entering energy}} \times 100$
	Entering energy = energy entering to each voltage level. *Delivered energy = net energy delivered at each voltage level.* Shows energy losses in the T-D network by voltage level. It is an indicator of the efficiency of the T-D network.
T-D Non-Served Energy (‰)	$\frac{\textit{Non served energy}}{\textit{Total energy delivered} + \textit{Non served energy}} \times 1000$
	Measures energy not delivered due to T-D interruptions. It is an indicator of T-D service reliability.
SAIFI System Average Interruption Frequency Index	$\frac{\sum \textit{Total number of customers interrupted}}{\textit{Total number of customers served}}$
	Reliability index representing how often the customers experience sustained interruptions in average. Sustained interruptions are those longer than five minutes.
SAIDI System Average Interruption Duration Index (hours)	$\frac{\sum \textit{Customer interruption durations}}{\textit{Total number of customers served}}$
	Reliability index representing the average duration of service sustained interruptions for customers. Sustained interruptions are those longer than five minutes.
Average Restoration Time (minutes)	$\frac{\sum \textit{Interruption durations}}{\textit{Total number of interruptions}}$
	Reliability index representing the average time required to restore service after an interruption.
Voltage and Frequency Deviations (#)	*Number of deviations from standard operating range*
	Number of annual voltage and frequency deviations from the standard operating range of variation. They are measures of power quality.
	Economical
Transmission-Distribution Cost (\$/MWh)	$\frac{\textit{Total T-D costs (\$)}}{\textit{Total energy delivered (MWh)}}$

TRANSMISSION-DISTRIBUTION INDICATORS	
Indicator	**Definition**
	Average T-D cost per MWh delivered. It is a measure of cost effectiveness of T-D operations.
Organizational	
Transmission-Distribution Productivity (man-years/ 10,000 MWh)	$\frac{\text{FTE of T - D staff (man - years)}}{\text{Total energy delivered (MWh)/ 10,000}}$
	Shows T-D staff utilization per 10,000 MWh delivered. It is a measure of productivity.

Table A1-4
Commercialization Indicators Definition

COMMERCIALIZATION INDICATORS	
Indicator	**Definition**
Technical	
Non-Technical Losses (%)	$\frac{\text{Available energy} - \text{Energy sold}}{\text{Available energy}} \times 100$
	Available energy= net energy generated + energy purchased – grid losses Shows energy losses due to non-registered consumptions (non-technical losses). It measures electricity delivered for which the utility is not paid.
Customers w/o Meter (%)	$\frac{\text{Number of customers without meter}}{\text{Total number of customers served}} \times 100$
	Shows the percentage of customers served whose consumption is not metered. It is an indicator of service efficacy.
Number of Complaints (#/1,000 customers)	$\frac{\text{Number of complaints}}{\text{Total number of customers served / 1,000}}$
	Shows the number of complaints received per 1,000 customers served. It is an indicator of customer service quality.
Economical	
Commercialization Cost ($/customer)	$\frac{\text{Total commercialization costs (\$)}}{\text{Total number of customers served}}$
	Average commercialization cost per costumer served. It is a measure of cost effectiveness of commercial activities.

COMMERCIALIZATION INDICATORS	
Indicator	**Definition**
Bad Debt (%)	$\frac{Bad\ debt\ (\$)}{Operational\ Revenues(\$)} \times 100$
	Measures receivables deemed uncollectible. It considers bills unpaid after 180 days.
Organizational	
Commercialization Productivity (man-years/1,000 customers)	$\frac{FTE\ of\ commercial\ staff\ (man - years)}{Total\ number\ of\ customers\ served\ /\ 1,000}$
	Shows commercial staff utilization per 1,000 customers served. It is a measure of productivity.

Annex 2

Tables with Performance Indicators of Chapter 3.3 Graphs

Table 1
Service Coverage (%)

(Section 3.3.1.1)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	100.0%	100.0%	100.0%	100.0%
2	BLPC	100.0%	100.0%	100.0%	100.0%
3	B	100.0%	100.0%	100.0%	100.0%
4	C	100.0%		100.0%	100.0%
5	D	100.0%			100.0%
6	E				100.0%
7	F				100.0%
8	G				100.0%
9	H	96.0%		98.0%	100.0%
10	*I*	*100.0%*	*100.0%*	*100.0%*	
11	J	100.0%		100.0%	
12	K	99.9%		100.0%	
13	L			99.8%	99.8%
14	M	99.8%		97.5%	99.3%
15	N	98.0%	100.0%		98.9%
16	O			97.0%	97.6%
17	P	96.0%	96.0%	96.0%	96.0%
18	Q	93.0%	93.0%	93.0%	93.0%
19	R	69.6%	65.3%	63.3%	72.4%
20	S	95.0%	95.0%	98.4%	
21	T				
22	U				
	Average 2002 =	96.5%			
	Average 2004 =	94.4%			
	Average 2005 =	96.2%			
	Average 2006 =	97.3%			
	Total average =	96.1%			
	Min 2006 =	72.4%			
	Max 2006 =	100.0%			

Table 2
System Energy Losses (%)

(Section 3.3.1.2)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				38.0%
2	B	17.7%	14.6%	18.0%	16.1%
3	C	14.4%	14.4%	15.4%	15.0%
4	D	11.5%	12.7%	13.4%	13.9%
5	E	7.3%			13.5%
6	F				10.9%
7	G	13.1%	10.1%	10.6%	10.5%
8	H	9.5%		11.7%	9.9%
9	I			9.4%	9.5%
10	J	10.4%	8.8%	8.7%	9.1%
11	K	9.0%		7.9%	8.1%
12	L				8.0%
13	BLPC	7.3%	7.2%	7.6%	7.5%
14	M				7.4%
15	N	18.5%	26.6%	33.1%	
16	O	17.8%	19.9%	22.3%	
17	P	13.2%	9.7%		
18	Q	4.4%		6.1%	
19	R	13.3%			
20	S	4.5%		2.0%	
21	T	10.1%			
22	U				
	Average 2002 =	11.4%			
	Average 2004 =	13.8%			
	Average 2005 =	13.9%			
	Average 2006 =	10.7%			
	Total average =	11.8%			
	Min 2006 =	7.4%			
	Max 2006 =	16.1%			

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Table 3
System Load Factor (%)

(Section 3.3.1.3)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				124.50%
2	B				101.30%
3	C	54.60%	64.60%	77.10%	77.70%
4	D			75.80%	76.70%
5	E	64.20%		76.20%	75.40%
6	F			66.60%	73.50%
7	G	75.70%		74.50%	73.40%
8	H	72.50%	72.60%	72.00%	72.80%
9	I	67.00%	70.60%	72.60%	71.60%
10	BLPC	70.10%	69.30%	66.40%	71.00%
11	J				69.10%
12	K	66.40%		70.30%	68.60%
13	L	75.70%		76.20%	67.70%
14	M	69.20%	67.30%	65.70%	65.40%
15	N	64.80%	58.70%	116.40%	
16	O	80.00%		77.80%	
17	P	69.20%	70.20%	73.40%	
18	Q	66.50%		65.20%	
19	R	75.30%	60.20%		
20	S	70.20%			
21	T	67.40%			
22	U				
	Average 2002 =	69.30%			
	Average 2004 =	66.69%			
	Average 2005 =	71.80%			
	Average 2006 =	71.90%			
	Total average =	69.92%			
	Min 2006 =	65.40%			
	Max 2005 =	77.70%			

Table 4
Average Energy Cost (US$/MWh)

(Section 3.3.1.4)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	203.96	332.60	420.00	358.08
2	B	162.64		220.19	338.89
3	C				315.17
4	D	174.18	235.24	251.61	274.32
5	E			209.71	228.65
6	F	154.28		279.00	226.43
7	G				224.64
8	H	86.54			191.29
9	I	157.64	159.20	192.77	190.41
10	J	158.27		173.01	180.35
11	K	129.64	120.14	160.94	175.50
12	BLPC	118.43	138.23	142.53	157.17
13	L	162.75	120.88	142.37	135.05
14	M	108.57		145.45	
15	N	249.68		204.50	
16	O	173.01		179.86	
17	P	108.57			
18	Q	145.32	193.81		
19	R	117.08	122.62		
20	S	193.50			
21	T				
22	U				
	Average 2002 =	153.18			
	Average 2004 =	177.84			
	Average 2005 =	209.38			
	Average 2006 =	230.46			
	Total average =	192.71			
	Min 2006 =	135.05			
	Max 2006 =	358.08			

Customer Service Rates

(Section 3.3.1.5)

Table 5
Domestic Rates for usage of 100 kWh/month

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				37.37
2	B	25.14	30.62	34.49	37.17
3	C	29.47		33.40	37.13
4	D	25.29		30.62	34.32
5	E			32.11	34.16
6	F	23.50	26.34		33.15
7	G	23.52	25.55	29.02	31.15
8	H	14.61			30.19
9	!	20.10	21.69	23.71	27.09
10	J				27.04
11	K	17.20	20.16	23.37	26.86
12	L	20.39	20.39	24.53	24.17
13	M	15.25	10.50	18.25	22.50
14	BLPC	16.65	19.62	20.60	21.71
15	N				20.20
16	O			4.39	4.14
17	P	24.80	28.04	32.10	
18	Q	15.80		18.50	
19	R	15.14	16.82		
20	S	21.11		21.11	
21	T	21.18			
22	U				

Average 2002 =	20.57
Average 2004 =	21.97
Average 2005 =	26.63
Average 2006 =	29.89
Total average =	24.77
Min 2006 =	20.20
Max 2006 =	37.37

Customer Service Rates

(Section 3.3.1.5)

Table 6
Domestic Rates for usage of 400 kWh/month

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	100.56	127.56	127.56	165.20
2	B				127.82
3	C	95.60		115.04	131.40
4	D	99.58		133.61	130.24
5	E	90.31	101.65		129.89
6	F			118.22	126.45
7	G	94.10	102.21	116.09	124.61
8	H	59.51	0.00		121.93
9	I	72.81	84.74	97.54	117.42
10	J	72.80	91.16	108.70	113.30
11	K				108.16
12	L	80.67	80.67	97.21	95.78
13	M	72.75	72.75	79.25	89.00
14	BLPC	65.03	76.92	80.84	85.28
15	N				81.00
16	O			16.61	16.59
17	P	96.10	111.44	125.46	
18	Q	59.87		70.46	
19	R	67.13	77.29		
20	S	77.31		77.30	
21	T	84.70			
22	U				
	Average 2002 =	80.55			
	Average 2004 =	92.64			
	Average 2005 =	104.91			
	Average 2006 =	117.60			
	Total average =	98.93			
	Min 2006 =	81.00			
	Max 2006 =	165.20			

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Customer Service Rates

(Section 3.3.1.5)

Table 7
Commercial Rates for usage of 2,000 kWh/month

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	566.82	686.00	755.50	939.50
2	B				702.30
3	C	545.40		737.80	698.70
4	D	527.42	567.16	636.53	679.11
5	E	454.20	513.82	577.87	677.24
6	F	337.30			653.10
7	G	470.60		567.38	649.22
8	H	456.37	513.20		648.21
9	I	0.00		577.50	618.70
10	J				606.40
11	K	436.00	479.01	568.19	591.31
12	BLPC	368.10	427.50	447.20	469.40
13	L	392.18	392.18	474.86	467.71
14	M	400.75	400.75	415.25	457.00
15	N				256.50
16	O			85.80	167.08
17	P	600.00	595.94	642.07	
18	Q	306.30		359.00	
19	R	301.46	301.49		
20	S	403.50		403.55	
21	T	444.10			
22	U				

Average 2002 =	438.16
Average 2004 =	487.71
Average 2005 =	557.58
Average 2006 =	632.71
Total average =	529.04
Min 2006 =	457.00
Max 2006 =	939.50

Customer Service Rates

(Section 3.3.1.5)

Table 8
Commercial Rates for usage of 5,000 kWh/month

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	1413.10	1711.10	1904.70	2344.20
2	B	1318.50	1417.90	1591.33	1697.79
3	C	1135.50	1284.56	1444.66	1693.11
4	D				1633.80
5	E	1140.93	1283.01		1623.17
6	F	1173.90		1415.54	1620.13
7	G	827.00			1614.90
8	H	1212.10		1705.40	1595.40
9	I			1438.70	1541.60
10	J	1091.00	1197.53	1420.91	1478.30
11	K				1347.80
12	BLPC	914.50	1063.10	1112.20	1167.70
13	L	957.50	957.50	1060.00	1150.00
14	M	960.90	960.89	1167.60	1149.72
15	N				627.70
16	O			218.50	417.02
17	P	1422.50	1457.56	1597.79	
18	Q	763.60		895.30	
19	R	737.42	673.16		
20	S	1008.90		1008.86	
21	T	1110.20			
22	U				

Average 2002 =	1074.22
Average 2004 =	1200.63
Average 2005 =	1366.38
Average 2006 =	1546.97
Total average =	1297.05
Min 2006 =	1149.72
Max 2006 =	2344.20

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Customer Service Rates

(Section 3.3.1.5)

Table 9
Industrial Rates for usage of 10,000 kWh/month

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	2595.06	3142.84	3530.11	4312.12
2	B				3344.45
3	C	1719.00			3300.80
4	D	2345.40		2827.17	3238.32
5	E	2271.00	2569.10	2889.32	3238.25
6	F	2323.20		3318.18	3089.95
7	G			2873.94	3079.76
8	H	1755.80	2440.22	2787.08	3000.00
9	I	1877.03	2136.72		2818.49
10	J	1838.00	1962.36	3228.14	2805.76
11	K				2670.40
12	L	1941.70	1941.70	2324.02	2288.27
13	BLPC	1777.27	2074.42	2172.60	2283.67
14	M	1882.50	1882.50	2085.00	2250.00
15	N				1282.50
16	O			556.45	1198.55
17	P	2918.80	3221.40	3151.29	
18	Q	1525.80		1789.23	
19	R	1168.87	1412.83		
20	S				
21	T	1956.60			
22	U				
	Average 2002 =	1993.07			
	Average 2004 =	2278.41			
	Average 2005 =	2748.00			
	Average 2006 =	2980.02			
	Total average =	2499.87			
	Min 2006 =	457.00			
	Max 2006 =	939.50			

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Customer Service Rates

(Section 3.3.1.5)

Table 10
Industrial Rates for usage of 100,000 kWh/month

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	25910.70	31388.60	35261.30	43075.35
2	B	16727.50			32830.53
3	C	23623.60		28467.00	32365.61
4	D	22709.70	24218.78	27420.96	30940.23
5	E	17468.00	24313.65	27782.29	29911.44
6	F				29500.50
7	G	21666.80		31690.70	29333.92
8	H			26085.90	28144.06
9	I	18751.80	21367.20		28105.37
10	J	16415.00	19623.62	32281.32	26798.08
11	K				26607.00
12	BLPC	17729.50	20701.10	21682.90	22793.52
13	L	19279.40	19279.40	21731.80	22770.95
14	M	17682.50	17682.50	18835.00	21200.00
15	N				5940.00
16	O			2726.98	4695.45
17	P	27712.20	29309.12	31439.11	
18	Q	14779.20		16712.60	
19	R	9979.53	13484.91		
20	S				
21	T	19565.90			
22	U				
	Average 2002 =	19333.42			
	Average 2004 =	22136.89			
	Average 2005 =	26615.00			
	Average 2006 =	28884.04			
	Total average =	24242.34			
	Min 2006 =	21200.00			
	Max 2006 =	43075.35			

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Table 11
Operational Profit Margin (%)

(Section 3.3.1.6)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A			-14.6	37.2
2	B	14.8		10.3	19.2
3	C	13.2	15.7	16.7	18.4
4	D	20.8		17.0	16.8
5	E	5.7	8.1	15.3	12.9
6	F	17.9	22.5	16.8	15.6
7	G	14.6	9.1	12.9	11.6
8	H				11.5
9	I	13.2	5.1		8.5
10	J	3.9	7.3	8.1	8.2
11	BLPC	11.9	12.8	9.8	6.4
12	K	4.0	-0.3	10.7	4.9
13	L	21.1			4.3
14	M	4.9	4.0	4.4	3.6
15	N				-0.8
16	O				-19.9
17	P	14.3		12.0	
18	Q	6.8		2.4	
19	R	5.8	11.1		
20	S	-7.5			
21	T	-13.1			
22	U				
	Average 2002 =	9.0			
	Average 2004 =	9.5			
	Average 2005 =	9.4			
	Average 2006 =	8.1			
	Total average =	9.0			
	Min 2006 =	-19.9			
	Max 2006 =	19.2			

Table 12
Return on Assets (%)

(Section 3.3.1.7)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	13.1		9.9	24.3
2	B	9.4	14.0	12.2	12.5
3	C	3.0	4.4	12.7	12.2
4	D	7.5			12.0
5	E	9.2	4.4		10.3
6	F	8.8	7.0	10.4	10.0
7	G			0.0	8.7
8	H	6.7	7.1	6.1	8.0
9	I	0.0		-13.0	7.4
10	J	8.1		8.1	7.3
11	K	3.3	-0.2	8.0	4.1
12	BLPC	6.7	7.1	6.1	4.1
13	L	1.6	3.3	3.9	4.1
14	M	2.6	2.6	3.7	3.2
15	N				-0.5
16	O				-11.5
17	P	8.0		17.3	
18	Q	8.2		1.7	
19	R	-4.2			
20	S	-8.2			
21	T				
22	U				

Average 2002 =	4.9
Average 2004 =	5.0
Average 2005 =	6.7
Average 2006 =	7.3
Total average =	6.0
Min 2006 =	-11.5
Max 2006 =	24.3

Table 13
Debt Level (%)

(Section 3.3.1.8)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	42.6	81.4	49.7	56.3
2	B	39.3	36.8		50.3
3	C			98.6	50.2
4	D	47.4		52.8	47.5
5	E	40.9		50.1	46.9
6	F			33.0	45.8
7	G	47.7	39.2	37.5	35.1
8	H	42.0	44.3	45.9	31.7
9	I	25.7	17.5	25.6	31.0
10	J	47.2	49.4	42.6	30.4
11	K	38.0	32.2	30.4	28.6
12	L	40.9	39.1	32.4	28.4
13	M				23.0
14	BLPC	14.0	24.6	22.5	19.2
15	N	18.2			14.8
16	O	146.9		84.8	
17	P	25.8		40.4	
18	Q	27.2	52.6		
19	R	54.7			
20	S	24.7			
21	T				
22	U				

Average 2002 =	36.0
Average 2004 =	41.7
Average 2005 =	46.2
Average 2006 =	35.9
Total average =	40.0
Min 2006 =	14.8
Max 2006 =	56.3

Table 14
Labor Productivity (man-years/1,000 customers)

(Section 3.3.1.9)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A			13.09	13.16
2	B	5.33	5.11	11.16	10.73
3	C	9.26			10.32
4	D	10.56		10.13	10.13
5	E	12.54		12.62	9.85
6	F				9.69
7	G	14.93		9.07	9.43
8	H	8.08	7.86	7.76	7.84
9	I	8.97	6.94	5.50	6.75
10	J			7.44	6.71
11	K	5.96	13.03		6.41
12	BLPC	4.63	4.48	4.60	4.51
13	L	4.93	4.54	4.43	4.18
14	M	4.38	4.06	3.54	3.42
15	N				3.16
16	O	10.52	9.91	8.94	
17	P	5.25		4.57	
18	Q	3.21	2.84	3.32	
19	R	8.02			
20	S	14.00			
21	T				
22	U				

Average 2002 =	8.16
Average 2004 =	6.53
Average 2005 =	7.58
Average 2006 =	7.75
Total average =	7.51
Min 2006 =	3.16
Max 2006 =	13.16

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Table 15
Safety incident rate (# incidents/100 employees)

(Section 3.3.1.10)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				6.36
2	B			3.97	5.54
3	C	4.56		2.50	4.71
4	D	1.53	3.73	1.23	3.29
5	E	3.61			3.08
6	F			2.65	2.86
7	G	3.27		2.80	2.80
8	H			1.75	2.33
9	BLPC	3.49	1.84	2.71	1.75
10	I			1.22	1.43
11	J	1.67	0.85	0.85	1.32
12	K	4.76	6.60		1.27
13	L	16.04	12.73	1.24	1.08
14	M	5.51	1.99	2.53	
15	N	1.42	1.64	1.80	
16	O	2.60			
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				
	Average 2002 =	4.41			
	Average 2004 =	4.20			
	Average 2005 =	2.10			
	Average 2006 =	2.91			
	Total average =	3.40			
	Min 2006 =	1.08			
	Max 2006 =	6.36			

Table 16
Generation Reserves Margin (%)

(Section 3.3.2.1)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	92.60	92.00	75.70	118.70
2	B	65.90	49.30		112.30
3	C	104.10		63.30	106.50
4	D	71.40	78.10	68.10	93.50
5	E	49.40		15.10	70.10
6	F	55.80	66.50	63.50	62.40
7	G				59.50
8	BLPC	58.60	49.40	56.90	54.10
9	H	21.00	59.50	44.40	46.70
10	I	53.00	21.90	36.20	34.50
11	J			36.50	34.30
12	K			33.50	31.90
13	L	62.20	73.60	87.40	
14	M	76.90		80.40	
15	N	123.60		61.30	
16	O	38.40	9.00		
17	P	91.00			
18	Q	71.10			
19	R	98.00			
20	S				
21	T				
22	U				
	Average 2002 =	70.81			
	Average 2004 =	55.48			
	Average 2005 =	55.56			
	Average 2006 =	68.71			
	Total average =	62.64			
	Min 2006 =	31.90			
	Max 2006 =	118.70			

Table 17
Generation Availability (%)

(Section 3.3.2.2)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	93.10	94.60		91.40
2	B	90.80	89.20		88.70
3	BLPC	89.10	88.50	77.60	87.60
4	C	79.60	92.10	88.20	86.10
5	D				82.80
6	E	82.40			78.80
7	F	83.80		77.40	78.10
8	G				72.10
9	H	82.10		46.50	43.80
10	I	77.90	77.10	82.90	
11	J	77.20	86.00	72.60	
12	K	93.80		68.70	
13	L	89.50	89.50		
14	M	93.10	81.40		
15	N	86.80			
16	O	86.40			
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				
	Average 2002 =	86.11			
	Average 2004 =	87.30			
	Average 2005 =	73.41			
	Average 2006 =	78.82			
	Total average =	81.41			
	Min 2006 =	43.80			
	Max 2006 =	91.40			

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Table 18
Plant Energy Consumption (%)

(Section 3.3.2.3)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	11.4	3.5	19.9	10.9
2	B			11.7	10.2
3	C	5.1			5.3
4	D	6.7	3.8	3.5	5.2
5	BLPC	3.8	3.5	4.0	4.3
6	E	4.2	3.9	4.1	4.0
7	F	4.1	4.3	3.9	3.8
8	G	2.5	3.6		3.2
9	H				3.1
10	I				3.1
11	J	1.3	16.2	1.2	2.9
12	K	5.1		2.3	2.1
13	L	10.9	11.4	1.2	1.9
14	M	2.9		1.9	1.5
15	N	2.0	3.2	0.3	0.2
16	O	8.9		6.9	
17	P	6.5		0.2	
18	Q	4.2	4.2		
19	R	12.9			
20	S				
21	T				
22	U				
	Average 2002 =	5.8			
	Average 2004 =	5.8			
	Average 2005 =	4.7			
	Average 2006 =	4.1			
	Total average =	5.1			
	Min 2006 =	0.2			
	Max 2006 =	10.9			

KEMA

Table 19
Utilization Factor (%)

(Section 3.3.2.4)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	49.4	62.0	55.1	56.4
2	B	0.0		49.5	51.9
3	BLPC	45.9	49.6	46.8	48.1
4	C	48.0	46.1	48.5	43.6
5	D				42.5
6	E	46.9		47.0	42.1
7	F	45.0	41.2	40.7	41.5
8	G	46.6	41.8		36.4
9	H	33.5		43.0	33.7
10	I	30.0	34.7	38.6	31.4
11	J	21.6	19.7	23.1	8.9
12	K	43.9		43.3	
13	L	38.2		37.5	
14	M	45.0		35.7	
15	N	45.2	50.0		
16	O	42.0			
17	P	34.1			
18	Q	40.5			
19	R				
20	S				
21	T				
22	U				
	Average 2002 =	41.0			
	Average 2004 =	43.1			
	Average 2005 =	42.4			
	Average 2006 =	39.7			
	Total average =	41.6			
	Min 2006 =	8.9			
	Max 2006 =	56.4			

KEMA

Table 20
Generation Non-Served Energy (o/oo)

(Section 3.3.2.5)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				2.540
2	B	1.260			2.170
3	C	0.610		4.700	0.550
4	D				0.440
5	E				0.440
6	F	0.100	1.190	0.230	0.420
7	G			0.320	0.310
8	BLPC	0.210	0.060	0.114	0.140
9	H	0.410		0.110	0.110
10	I				0.030
11	J	1.770		11.120	
12	K	0.700		0.260	
13	L	5.350	0.140	0.090	
14	M	0.520	0.650	0.110	
15	N				
16	O				
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				

Average 2002 =	1.214
Average 2004 =	0.510
Average 2005 =	0.840
Average 2006 =	0.715
Total average =	0.820
Min 2006 =	0.030
Max 2006 =	2.540

KEMA

Fuel and Generation Costs

(Section 3.3.2.6)

Table 21
Fuel Costs (US$/MWh)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	77.88	110.18	152.43	202.55
2	B	65.74	82.43	171.23	198.35
3	C	48.14	71.73	154.44	177.37
4	D				169.10
5	E			104.85	164.29
6	F	86.58		180.82	146.75
7	G	71.67		138.72	143.02
8	H	63.55	85.49		136.30
9	I	52.82	78.35	108.32	133.16
10	J				115.43
11	K	50.24			101.41
12	BLPC	58.79	80.22	88.98	95.77
13	L	53.31		96.79	95.33
14	M	58.99	66.16	57.18	75.30
15	N	41.96	29.19	47.78	62.23
16	O	0.00			12.18
17	P	76.22		107.62	
18	Q	49.39		122.50	
19	R	73.83	102.14		
20	S	58.29			
21	T				
22	U				
	Average 2002 =	61.71			
	Average 2004 =	78.43			
	Average 2005 =	117.82			
	Average 2006 =	126.78			
	Total average =	96.19			
	Min 2006 =	12.18			
	Max 2006 =	202.55			

KEMA

Fuel and Generation Costs

(Section 3.3.2.6)

Table 22
Generation Costs (US$/MWh)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				276.52
2	B	142.82	227.99	286.91	266.95
3	C	104.49		169.90	262.43
4	D	93.98	149.11	173.65	194.04
5	E			157.28	193.08
6	F	119.51		234.52	190.33
7	G				171.82
8	H	67.60			151.88
9	I	92.94	101.15	139.66	146.61
10	J	108.32		139.99	145.59
11	BLPC	84.97	107.18	114.50	130.20
12	K	70.73	76.89	88.94	115.09
13	L	98.25	39.77	117.20	108.92
14	M	77.77	65.73	81.18	97.53
15	N	143.29		160.91	
16	O	153.60		125.84	
17	P	103.69	125.21		
18	Q	83.69	100.50		
19	R	127.36			
20	S				
21	T				
22	U				

Average 2002 =	104.56
Average 2004 =	110.39
Average 2005 =	153.11
Average 2006 =	175.07
Total average =	135.78
Min 2006 =	97.53
Max 2006 =	276.52

KEMA

Table 23
Generation Productivity (man-years/10 MW)

(Section 3.3.2.7)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A		30.48	39.46	34.61
2	B	35.93	34.15	28.52	30.65
3	C			19.44	20.26
4	D	10.54	12.32	10.15	9.55
5	E	14.33		10.99	7.43
6	F	14.71	16.55		7.16
7	G	7.64		9.00	6.55
8	H				6.10
9	BLPC	6.04	6.08	5.91	5.95
10	I	17.87	9.69	5.76	5.89
11	J	7.31	4.11	4.25	4.07
12	K			0.14	0.14
13	L	23.96	19.33	19.48	
14	M	20.91		16.79	
15	N	6.17		12.39	
16	O	4.32	4.98		
17	P	11.52			
18	Q	5.61			
19	R	11.11			
20	S				
21	T				
22	U				
	Average 2002 =	12.37			
	Average 2004 =	15.30			
	Average 2005 =	14.02			
	Average 2006 =	11.53			
	Total average =	13.31			
	Min 2006 =	0.14			
	Max 2006 =	34.61			

KEMA

Table 24
Energy Grid Losses (%)

Too little data has been provided by participants as to be seen in this table.
For that reason so this performance indicator could not be benchmarked in Section 3.3

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	9.55	8.90	8.56	9.00
2	B	4.05		3.10	3.10
3	C	7.00		7.00	
4	D	9.40	15.50		
5	E	10.40	8.90		
6	BLPC	7.40	7.00		
7	F	10.90			
8	G	10.60			
9	H	10.10			
10	I	10.00			
11	J	8.90			
12	K	8.90			
13	L	8.70			
14	M	6.50			
15	N	5.00			
16	O	3.50			
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				

Average 2002 =	8.18
Average 2004 =	10.08
Average 2005 =	6.22
Average 2006 =	6.05
Total average =	7.63
Min 2006 =	3.10
Max 2006 =	9.00

Table 25
T&D non-served energy (o/oo)

Too little data has been provided by participants as to be seen in this table.
For that reason so this performance indicator could not be benchmarked in Section 3.3

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				1.440
2	B	1.680	0.730	0.760	0.720
3	C				0.660
4	D			1.100	0.660
5	BLPC	0.410	0.510	0.220	0.370
6	E	0.610		0.160	0.200
7	F				0.180
8	G	1.400		0.550	
9	H	6.060	4.370		
10	I	3.150			
11	J	0.030			
12	K				
13	L				
14	M				
15	N				
16	O				
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				
	Average 2002 =	1.906			
	Average 2004 =	1.870			
	Average 2005 =	0.558			
	Average 2006 =	0.604			
	Total average =	1.235			
	Min 2006 =	0.180			
	Max 2006 =	1.440			

Network Reliability

(Section 3.3.3.1)

Table 26
SAIFI

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				17.48
2	B			11.37	9.89
3	C	3.30		3.77	8.02
4	D	12.09	8.91	10.53	6.88
5	E	11.48	8.54	4.07	4.35
6	F				1.58
7	G	20.35	0.84		1.11
8	H			1.00	1.03
9	BLPC		9.83	10.5	12.56
10	I	0.17			0.23
11	J				0.03
12	K		8.65	0.05	
13	L	2.13	2.30		
14	M	1.00	0.06		
15	N				
16	O				
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				
	Average 2002 =	7.22			
	Average 2004 =	5.59			
	Average 2005 =	5.90			
	Average 2006 =	5.74			
	Total average =	6.07			
	Min 2006 =	0.03			
	Max 2006 =	17.48			

Network Reliability

(Section 3.3.3.1)

Table 27
SAIDI (hours)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A			75.96	38.88
2	B				10.20
3	C	9.73		7.20	6.57
4	BLPC		4.83	2.77	4.97
5	D	2.81		8.02	3.77
6	E	11.49	6.96	7.84	3.25
7	F				2.18
8	G			18.48	1.65
9	H				0.09
10	I			0.05	0.05
11	J	25.12	7.78	8.57	
12	K			0.23	
13	L		9.35		
14	M		0.94		
15	N				
16	O				
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				
	Average 2002 =	12.29			
	Average 2004 =	5.97			
	Average 2005 =	14.35			
	Average 2006 =	7.95			
	Total average =	10.36			
	Min 2006 =	0.05			
	Max 2006 =	38.88			

Table 28
Transmission & Distribution Costs (US$/MWh)

(Section 3.3.3.2)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	49.56	65.45	72.96	69.99
2	B	61.80		65.56	67.64
3	C	46.31	43.63	89.47	56.07
4	D	45.94		28.62	40.81
5	E				40.15
6	F	58.85	32.44	46.48	37.76
7	G	14.36			35.43
8	H	34.75		26.11	27.61
9	I			11.04	27.35
10	J	25.76		26.18	26.18
11	BLPC	27.11	27.31	21.58	23.06
12	K			39.16	20.64
13	L				18.84
14	M	58.91	20.76	17.86	18.63
15	N	69.48		100.95	
16	O	108.84		45.42	
17	P	19.29		27.48	
18	Q	39.30	47.92		
19	R	51.74			
20	S	26.51			
21	T				
22	U	-			
	Average 2002 =	46.16			
	Average 2004 =	39.59			
	Average 2005 =	44.21			
	Average 2006 =	36.44			
	Total average =	41.60			
	Min 2006 =	18.63			
	Max 2006 =	69.99			

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Table 29
Transmission & Distribution Productivity (man-years/10,000 MWh)

(Section 3.3.3.3)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	11.10		6.79	9.77
2	B	5.19	6.97		6.36
3	C		4.69	1.66	4.81
4	D	1.82	1.96	4.47	4.29
5	E	4.49		4.40	3.40
6	F	4.50	3.21	3.00	2.95
7	G			3.18	2.84
8	H			2.43	2.55
9	BLPC	2.20	2.50	1.99	2.11
10	I	2.61	2.25	2.13	1.97
11	J	3.35		1.89	1.71
12	K	1.00			1.68
13	L	1.28		1.20	1.20
14	M				0.96
15	N				0.78
16	O	9.92		9.92	
17	P	3.83		3.20	
18	Q	1.42		1.25	
19	R	1.77		1.00	
20	S	2.45			
21	T				
22	U				
	Average 2002 =	3.80			
	Average 2004 =	3.60			
	Average 2005 =	3.23			
	Average 2006 =	3.38			
	Total average =	3.54			
	Min 2006 =	1.00			
	Max 2006 =	9.92			

Table 30
Non-Technical Losses (%)

Too little data has been provided by participants as to be seen in this table.
For that reason so this performance indicator could not be benchmarked in Section 3.3

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	2.50	1.20	2.10	
2	B				
3	C				
4	D				
5	E				
6	F				
7	G				
8	BLPC				
9	H				
10	I				
11	J	9.60			
12	K	9.50			
13	L	7.70			
14	M	6.30			
15	N	5.00			
16	O	2.50			
17	P	2.50			
18	Q	2.50			
19	R	2.30			
20	S	1.00			
21	T	0.80			
22	U	0.60			
	Average 2002 =	4.06			
	Average 2004 =	1.20			
	Average 2005 =	2.10			
	Average 2006 =	n.a			
	Total average =	n.a			
	Min 2006 =	n.a			
	Max 2006 =	n.a			

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Table 31
Number of Complaints (#/1,000 customers)

(Section 3.3.4.1)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	55.75	125.11		148.24
2	B	67.99	132.78	136.97	127.82
3	C				62.23
4	D	67.50		77.85	24.92
5	E				23.18
6	F				0.93
7	G	7.00	6.71	1.61	0.70
8	H	174.81	328.81	148.34	
9	BLPC	159.79		30.10	19.91
10	I	51.70	53.01	0.15	
11	J	136.51			
12	K	88.72			
13	L	73.23			
14	M	10.90			
15	N				
16	O				
17	P				
18	Q				
19	R				
20	S				
21	T				
22	U				
	Average 2002 =	81.26			
	Average 2004 =	129.28			
	Average 2005 =	65.84			
	Average 2006 =	55.43			
	Total average =	82.95			
	Min 2005 =	0.70			
	Max 2005 =	148.24			

KEMA

Table 32
Commercialization Costs (US$/customer)

(Section 3.3.4.2)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	163.07		277.41	450.46
2	B				354.58
3	C	199.93	245.01	348.89	329.67
4	D	263.83		280.61	280.61
5	E			211.69	201.77
6	F	148.32			201.20
7	G	62.07		169.50	189.21
8	H	269.04		167.45	184.38
9	I				181.16
10	J			33.16	75.96
11	K	89.25	179.00	81.03	68.75
12	L	91.98	168.05	72.26	67.20
13	M	68.85	38.58	58.13	59.88
14	BLPC	76.66	56.11	78.11	58.52
15	N	248.74	276.26	312.10	
16	O	125.66		25.56	
17	P	36.14	225.44		
18	Q	85.14	57.75		
19	R	234.01			
20	S	139.63			
21	T				
22	U				

Average 2002 =	143.90
Average 2004 =	155.78
Average 2005 =	162.76
Average 2006 =	193.10
Total average =	163.88
Min 2006 =	58.52
Max 2006 =	450.46

KEMA

Table 33
Bad Debt (%)

(Section 3.3.4.3)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A	19.60		2.90	17.65
2	B	1.00		1.30	3.43
3	C				2.46
4	D	0.90		1.90	2.10
5	E			0.50	1.83
6	F	2.80	2.00	1.80	1.58
7	G				0.74
8	H				0.56
9	I	0.30		0.40	0.43
10	J	7.80	3.70	0.40	0.41
11	K	0.80			0.34
12	L	3.80	5.10	7.00	0.15
13	BLPC	0.00	0.00	0.10	0.05
14	M			6.30	
15	N	0.20		0.40	
16	O	6.70			
17	P	6.10			
18	Q	4.10			
19	R	1.40			
20	S	0.00			
21	T	0.00			
22	U	0.00			
	Average 2002 =	2.56			
	Average 2004 =	2.70			
	Average 2005 =	1.92			
	Average 2006 =	1.17			
	Total average =	2.09			
	Min 2006 =	0.05			
	Max 2006 =	3.43			

Table 34
Commercialization Productivity (man-years/1,000 customers)

(Section 3.3.4.4)

#	Utility	Indicator 2002	Indicator 2004	Indicator 2005	Indicator 2006
1	A				2.910
2	B	1.000			1.910
3	C	1.450		1.150	1.530
4	D	1.180		1.140	1.140
5	E	0.990	0.980	1.130	1.100
6	F	1.830	1.210	1.610	1.090
7	G				0.990
8	H				0.890
9	I			1.090	0.800
10	J		1.130	1.150	0.680
11	BLPC	0.740	0.740	0.650	0.670
12	K	0.760	0.760	0.640	0.660
13	L	1.020		0.920	0.560
14	M	0.630	0.560	0.550	0.530
15	N	0.830	1.250	1.460	
16	O	1.180		1.100	
17	P	1.280	1.190	0.280	
18	Q	1.270			
19	R	0.880			
20	S	0.660			
21	T				
22	U				
	Average 2002 =	1.047			
	Average 2004 =	0.978			
	Average 2005 =	0.990			
	Average 2006 =	1.104			
	Total average =	1.030			
	Min 2006 =	0.530			
	Max 2006 =	2.910			

5

CASE NO. 5

Barbados Light and Power Company Limited

Board's Decision dated 14th March, 1974

BARBADOS.

PUBLIC UTILITIES BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT 1951 (1953-31)

and

IN THE MATTER OF THE RATES PROPOSED BY THE BARBADOS LIGHT AND POWER COMPANY LIMITED ON THE 27th day of December, 1973.

Mr. J.S.B. Dear, Q.C., and Mr. H.B. St.John, Q.C., for the Barbados Light and Power Company Limited.

DECISION

On December 27, 1973, the Barbados Light and Power Company Limited (hereinafter called "the Company") submitted to the Public Utilities Board (hereinafter called "the Board") a Schedule of new rates for electric service which the Company proposed to put into effect as of March 1, 1974. This Schedule is shown as Appendix A which is annexed hereto.

After a preliminary analysis of the Company's proposed rates the Board decided upon its own motion that it would enter into a public hearing to determine whether the rates proposed by the Company were fair and reasonable.

The Board therefore gave notice to the public of the Company's proposed rates, showing existing rates for comparison, and invited public complaints against the proposed rates.

The Bajan Consumer League alone complained but later withdrew its objection.

In accordance with the provisions of the Public Utilities Act 1953-51 Messrs. Kenneth R. Hewitt, a Chartered Accountant, and Stephen Leacock, an Attorney-at-Law and Lecturer in Business Law at the University of the West Indies, were appointed assessors to assist the Board in determining the matters

arising

arising during the public hearing.

RATE BASE

The law requires the Board to allow the Company to earn a fair return on the fair value of its property used and useful in its public service. But nowhere does it spell out how to determine the fair value of a utility's property used and useful in its public service. In previous rate enquiries in Barbados the parties have agreed on fair value as being the book costs depreciated of the Company's property so used and useful. (Refer to Barbados Telephone Co. Ltd. rate enquiry 1972) At this enquiry however the Company has invited the Board to determine fair value as being the reproduction cost new less depreciation of the Company's property used and useful in providing its public service. The Company has adduced evidence of experts as to the value reproduction cost new less depreciation of the Company's property and as to the method of determining such value.

To quote from the valuation report of the Company's plant and property done by International Middle West Service Company, management and engineering consultants, which was received in evidence -

> "For most of the plant the above values are the result of applying trend multipliers to the direct costs by vintage years as recorded in the Company's books for the period January 1, 1965, through December 31, 1972, and to the RCN value established at December 31, 1964. For the remaining items, the inventory of property at December 31, 1972, was priced at current cost levels. Current unit cost pricing was also used to check some of the values obtained by trending."

and further on -

> "...determination of current costs by trend multipliers required a determination of the trendable labor and material cost base by year of installation for property remaining in service at December 31, 1972. This involved first the elimination of all general overhead costs from amounts recorded on the Company's Assets Register and all overhead in the RCN values established at December 31, 1964. The amounts remaining were further reduced to reflect elimination of some unrecorded retirements."

"The current cost pricing involved the application of unit

unit costs determined on the basis of current labor and material costs to an inventory derived partly from 100% inspection and partly by random sampling.

Trend multipliers were used for most property items to convert the book costs as described above to current costs at December 31, 1972. A different set of multipliers was developed for each class of property items. Each trend multiplier in a set is a ratio of the cost of labor and material at December 31, 1972, to the cost of labor and material for the same class of items constructed at the applicable date. Various methods were employed to develop the trend multipliers.

Present day prices were received from the manufacturers of the major items of generating plant and substation equipment. The ratio of such current prices to the cost originally experienced was used as the basis for the trend multipliers developed for these classes of equipment.

For the mass property in the distribution plant, purchase records and job orders were analyzed to develop the average cost of the material and cost of installation that had been experienced over the past years. Payroll labor costs for the different classifications of construction labor were obtained and used in developing the trend multipliers.

The present day freehold value of land and residential buildings owned by the Company was determined by a local appraiser familiar with the land values and residential property construction in Barbados. We participated in instructing this appraiser as to the scope of such an appraisal required for purposes of this report."

After the current cost values of all items of the Company's plant were determined there were added general overhead costs with varying percentages for different classes of property. The report goes on to state that these percentages (and I quote)

"included, where applicable, the stamp duty and expense of transferring land, engineering and supervision, administrative and general expense, interest during construction and financing charges. The amount included for interest during construction depended upon the length of the construction period and upon the timing of construction completion required for each of the various classes of plant items in scheduling completion of the entire plant and securing and connecting all consumers."

The overhead percentages applied to current cost values are shown in Appendix B which is annexed hereto.

To arrive at depreciation on the Reproduction Cost New of the Company's property the following methods were used. And I quote from the report .

"One

"One of these was the observed condition per cent of the property based on our inspection of the physical property of the Company and our discussions with Company personnel relative to plans for future changes to the property. The other was the determination of the condition per cent of the property on a present worth basis using estimated service lives and mortality dispersion. In most cases there was close agreement between the results of these two approaches and the final per cent condition involved a consideration of both."

Total plant Reproduction Cost New was therefore shown as $66,062,874, and total plant Reproduction Cost New less Depreciation as $54,094,203. The Company invites the Board to accept this figure as the fair value of the Company's property for determining its rate base.

In determing fair value the Board is of the view that Reproduction Cost New is not entirely satisfactory in arriving at fair value. And Mr. Fergusson, one of the Company's expert witnesses, states that the regulatory agencies and Courts in several fair value jurisdictions in the United States of America regard fair value as lying somewhere between original costs and Reproduction Costs New.

The Board has therefore paid due regard to the book costs and the Reproduction Cost New of the Company's property, and for the purpose of this hearing has accepted the method of valuation done by International Middle West Service Company, subject to disallowing overhead percentages which have been applied to various items and classes of property, and disallowing all items of intangible plant for the purpose of rate base determination.

The Board therefore determined the undepreciated fair value of the Company's fixed assets at December 31, 1972, as being $53,296,532, and their fair value less depreciation as $43,461,470. From the fair value undepreciated the Board then deducted $45,820,478, the undepreciated book costs of the Company's fixed assets at December 31, 1972, as shown in its audited accounts (Exhibit 31)

(Exhibit 31) and found a surplus at December 31, 1972, of $7,476,054.

In evaluating the Company's fixed assets at year end 1974 the Board therefore took the Company's fixed assets at December 31, 1973, being $52,963,000, added surplus of $7,476,054 and net additions (estimated cost of new plant under construction in 1974) of $17,104,000. The Company's fixed assets at year end 1974 are therefore valued at $77,543,054. (Particulars are shown in Appendix C)

For the purpose of determining the Company's rate base the Board then eliminated some items of property which are no longer used nor useful in rendering service to the public. These items are shown in Appendix D hereto, and are valued at $69,268.

The Board also considered whether the Company's land and buildings situate at Bush Hill which are used as residential quarters for some members of the staff of the Company were properly included in rate base as property used and useful in rendering public service. These properties according to valuation done by John N. Bladon and received in evidence are worth some $400,000. To this is added $125,000, the value of one half of the land and buildings on the site of the Garrison Hill on the east of the highway valued at $250,000. (The other half is used as offices). The total value of the Company's property used for residential purposes is taken as $525,000.

The value of household furniture used in these buildings, after deducting overhead costs, is $63,386.

Evidence further shows that annual expenses in relation to these properties is as follows - Repairs $8,235, Wages $12,963, Land Taxes approximately $600, Insurance (2½% of premium covering all of Company's buildings being $36,000) $900, making a total of $22,718.

$22,718. To this amount the Board then added a further amount of $58,839, being interest imputed at the rate of 10% per annum on $588,386, the total value of the Company's assets used for residential purposes.

The total annual expenses imputed to the Company's assets used for residential purposes is therefore $81,557.

The Board also notes from the evidence that the holders of 17 senior posts ranging from Managing Director down to qualified Engineer receive accommodation or an allowance in lieu. Of these, 12 receive cash allowances fully taxable at monthly rates ranging from $500 down to $250. The remaining 5 occupy Company dwellings and receive annual allowances in respect thereof totalling $3,810. The Board therefore considers that reasonable annual expenses allowable to the Managing Director and four senior staff living in Company dwellings should be $36,000 less $3,810, that is to say, $33,190. When compared with the expenses imputed in relation to these assets, there is a wide disparity in cost to the Company, and the Board considers it unreasonable that the consumers should bear this unnecessary burden. In any event, the Board is of the opinion that the use of Company assets for staff residences is marginally justifiable as property used and useful in rendering electric service to the public. And since use of such property in this case is most uneconomic, will disallow their value of $588,386 from the Company's rate base.

The Board therefore values the Company's fixed assets used and useful in rendering public service at year end 1974 at $76,885,400.

In determining the amount deductible for depreciation in respect of these assets the Board took the Company's accumulated depreciation at year end 1973 of $12,371,000. From this amount it deducted $1,073,807, being depreciation over-provided for on surplus

as

as at December 31, 1972, and added $276,897, being depreciation @ 3.705% allowed on surplus for 1973. For 1974 the Company provided depreciation of $2,658,000. From this figure the Board deducted $750,000, being depreciation over-provided for on surplus as at December 31, 1973, and added $276,987, being depreciation @ 3.705% allowed on surplus for 1974. The Board further deducted amounts for depreciation applicable to assets disallowed from the Company's rate base. As at December 31, 1972, the amount is $22,657, and for the years 1973 and 1974 the amounts are $24,366 in each year, calculated @ 3.705% on total assets disallowed amounting to $657,654.

Total depreciation allowed at year end 1974 is therefore $15,687,778. Detailed calculations are shown in Appendix C which is annexed hereto.

The Board therefore values the Company's used and useful fixed assets less depreciation at year end 1974 at $63,197,622.

WORKING CAPITAL

Working Capital (i.e. current assets less current liabilities) at year end 1974 is shown in Exhibit 23 as $2,848,000. This amount is added to net plant in service, and customer contributions estimated at $4,375,000 in 1974 are deducted.

The Board therefore finds that the Company's rate base at year end 1974 is $61,670,622. Details are shown in Appendix C hereto.

RETURN

It remains now to determine a fair return which the Company is entitled to earn on its rate base of $61,670,622. In so doing the Board has a responsibility to balance the interests of the investor and the Company on the one hand and the consumer on the other. From the investor or Company point of view it is important that the Company has enough revenue to cover its operating expenses (including maintenance, depreciation) and property taxes, to service its loan capital and preferred stock commitments, and

and to earn a sufficient return on its common equity to allow it to function as a viable economic enterprise. To adopt a statement from the Hope Natural Gas Case /Federal Power Commission v Hope Natural Gas Co. (51 P.U.R. N.S.193)7 and I quote -

> "That return moreover should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

From the consumer point of view the Board must ensure that the public gets good service (and I quote) "under efficient and economical management" at reasonable cost. To quote and adopt the language of another case - the Permian Basin Area Rate Cases 390 U.S. 747 (1968) - the Board is "obliged at each step of its regulatory process to assess the requirements of the broad public interests entrusted to its protection" by the Legislature. And further the "end result" of the Board's orders "must be measured as much by the success with which they protect those /public7 interests as by the effectiveness with which they maintain credit and attract capital'".

OPERATING EXPENSES

residencial expenses

As regards operating expenses, as stated above, the Board attributes $81,557 as expenses applicable to the Company's residential assets which the Board has taken out of rate base. Against this the Board considers $33,190 as shown above a reasonable expense allowable and therefore deducts the excess of $48,367 from operating expenses.

rate case expenses

Rate case expenses are to be written off over four years, so that $25,000 only is allowed for 1974.

depreciation ?

In relation to depreciation for 1974 the Board allows $2,161,000 after deducting $750,000® from the Company's provision of $2,658,000, adding back $276,987 allowed in its stead, and further deducting $24,366 depreciation @ 3.705% for 1974 on (total) assets of $657,654 disallowed.

income tax

The Board allows other taxes of $187,000, but disallows provision of $453,000 for income tax. The reason for disallowing income tax provision is this. Exhibit 21 shows ordinary

dividends

® over provision of surplus.

dividends net as $1,140,000. Preference dividends net are $16,000, making a total of $1,156,000 net. When grossed up, these dividends amount to $1,926,667. Income Tax withheld on this amount would be $770,667. The Company's provision for income tax of $453,000 is more than covered by the amount of tax withheld by the Company.

The Company's total requirement necessary to satisfy operating expenses (including maintenance and depreciation) and property taxes during 1974 is therefore reasonably estimated at $18,225,000.

To this amount is added interest requirements for 1974 estimated at $1,548,000, and dividends on preference shares estimated at $27,000 making total revenue requirements for these purposes in 1974 approximately $19,801,000.

For the Company to maintain its present rate of dividend on ordinary shares at 40 cents per share net or $66\frac{2}{3}$ cents per share gross, equivalent to $13\frac{1}{3}\%$ on par value, the Company would require additional revenue of approximately $1,900,000 for gross dividend on ordinary shares. This would make total requirements for 1974 $21,701,000.

On present rates, the Company's operating revenue in 1974 is estimated at $20,711,000. Interest during construction for this period is estimated at $512,000, making estimated total operating revenue for 1974 $21,223,000. This would result in a deficit of approximately $478,000 on present rates.

The rates proposed by the Company will yield projected revenue of $23,624,000 in 1974. Interest during construction of $512,000 makes total operating revenue of $24,136,000 in 1974. When operating expenses of $18,225,000 are deducted net operating

income

income amounts to $5,911,000. When interest on loan capital and preference dividends totalling $1,576,000 are deducted this leaves an amount of $ 4,335,000 to pay dividends on ordinary shares, and for surplus, a 13 per cent return on shareholders' equity estimated at $33,416,000.

In further analysing the effect of these projected revenues on the Company's overall financial position, the Board considered the Company's proposed capital programmes, particularly the installation of two new 20,000 kilowatt steam turbine plants.

To finance capital expenditure on the two new steam plants the Company proposes to borrow long term finance. The proposed lenders require their loans to be secured by the issue of debentures ranking "pari passu" with the Company's existing debenture holders, and that the Company must demonstrate its ability to provide sufficient earnings so that its gross income plus depreciation in any one year amount to at least 1.25 times the sum required for the Company to meet interest and capital repayments in the succeeding year.

In 1974, the Company's gross income on the proposed rates will be $5,399,000 and depreciation allowance $2,161,000, making a total of $7,560,000. In 1975 the Company's interest and capital repayments will amount to $5,097,000. On the abovementioned formula the ratio of 1.25 times would be satisfied.

In justifying proposed capital expenditure on these two new steam plants Mr. John Nelson, the Company's Managing Director, gave evidence that for many years the demand for electricity in Barbados had grown at a compounded rate of approximately 15% per annum or doubled every five years.

By 1973, the Company's forecasts of electric power loads and capacity requirements showed that the Company, on existing plant capacity, would not be able to supply the forecast

requirements

requirements for electric energy in 1975. Studies undertaken by the Company in 1972 showed that future additions to generating capacity could most economically be met by steam turbine plant and that two units of 20,000 kilowatt each should be installed for commissioning in late 1975 and early 1976 respectively. Evidence further showed that the lead time for this type of plant was 2½ years, and that, in order to meet the deadlines, the Company had placed orders for the plant in July 1973. Both plants were ordere at the same time, since analysis showed that considerable savings could be achieved by proceeding with the engineering, purchase, and installation of the second steam unit together with the first with a planned completion date of four to five months later.

In November 1973 the World Energy Shortage had its effect on the operations of the Company. In the words of Mr. Nels and I quote -

> "This required the production of electricity to be cut back 80% of the forecast November/December 1973 figure......the net effect of the fuel cut back has been an immediate and substantial drop in sales and revenue, with the forecast of 25% reduction of 1974 sales and revenue below previous estimates. Contrary to this trend in sales and in sympathy with current world-wide inflation, the majority of operating expenses are continuing to rise and are compounding the problem, thereby producing a drastically reduced gross income position. Although sales will be depressed in 1974 to appro mately the levels obtaining in 1972 the Company believes that the fuel situation will ease slightly in the future, and is therefore forecasting a 10% increase in the use of electricit in 1975 and 1976. Production capacity to carry this increas use will have to be provided. To fail to secure finance or cancel the orders for the new steam plant would preclude the possibility of development in the Barbados economy during 197 and thereafter."

It is perhaps appropriate to quote here the recommendations made by C.I. Power Services Ltd., the Company's engineering co sultants, which have been the basis of the Company's decision:-

> "On the basis of the studies we carried out in 1972, we recommended that the Barbados Light and Power Company Limite proceed with the installation of gas turbine and steam electr generating plants to meet their future electrical power needs According to our studies, expanding generating plant with ste electric plant, per program 2, would have higher capital cost by EC$12,660,000 over the diesel electric plant program, but

the

the reduction in operating costs by EC$34,165,000 would off set the higher capital cost and would result in a net saving of EC$21,505,000 over the 20 year, 1975 to 1992, period considered.

At a growth rate of 15% projected at that time, the second steam electric plant was required to go into operation in 1977, two years after the first plant. Our studies showed that there was a reduction in capital and operating costs of EC$2,676,000 and EC$1,870,000 respectively, for a total EC$4,546,000, if the second plant were designed and installed concurrently with the first plant. In view of this significant reduction we recommended that this latter program, program 3 in this report, be adopted, which it subsequently was. Since the development of the world fuel crisis in late 1973 the program has been modified to exclude a second gas turbine which was to have gone into operation in 1974.

On evaluating the steam electric program under present conditions of projected lower growth rate of electrical powe needs and fuel prices which have increased by over 3½ times the 1972 price level, we find that installing the second ste electric plant concurrently with the first, program 4, as opposed to deferring the second plant to 1978, program 5, wi result in a saving of EC$6,378,000. We therefore recommend that the installation date of the second steam electric plan remain as previously agreed."

The Board accepts the Company's evidence on this point and after examining the terms of the proposed loan arrangements ar satisfied that they appear reasonable in the circumstances.

The Board notes from the evidence that in 1973 the Company paid th. C.I. Power Services Ltd. approximately $1,000,000 for management and engineering services performed under contract. C.I. Power Services Ltd. is a subsidiary of C.I. Power Ltd., and both are incorporated in Canada. C.I. Power Ltd. is the majority shareholder in the Company.

To justify this expenditure the Company gave evidence of the substantial and specialist services C.I. Power Services Ltd. performed particularly in relation to negotiating finance at very reasonable cost, advising on organization and development programme obtaining special discounts for bulk purchasing, and arranging priority despatch of equipment in cases of emergency. The Board recognises the value of these services rendered, but would suggest

that

that in view of the present need to conserve foreign exchange, the company should make every effort to curtail such expenditure

After analysing all the evidence in this hearing, the Board is of the opinion that total operating revenue of $24,136,0 would be sufficient to enable the Company to meet its total financial commitments for the time being, and to enable it to function as a viable economic enterprise. The Board will therefore permi the Company to fix rates which will earn this revenue in 1974. With the projected growth in sales, these rates should earn the revenues required in subsequent years.

Net operating profit of $5,911,000 would yield a rate of return on the Company's rate base of $61,700,000 of 9.58%. The Board considers this a fair return.

RATE STRUCTURE

The World Energy Shortage in November 1973 and after resulted in reduced supplies of fuel to the Company. So that the Company's rates were inevitably too low for continued consistency with costs. Because of the continued erratic, sudden, and big increases in fuel prices, the Company in December 1973 requested the Board to allow the Company to apply a fuel adjustment clause to domestic users of electric energy. The Company had for several years been permitted to apply a fuel adjustment clause to all other consumers. The effect of such a clause is that it would operate automatically to adjust the charges for electric service to the extent required by changes in fuel costs. The Board therefore permitted the Company to apply a fuel adjustment clause to domestic consumers, so designed, that domestic users paid 2 cents per KWH less than other users.as from January 1, 197

At the time of this hearing, there is no evidence that fuel costs have as yet stabilised. It seems therefore more

appropriate

appropriate to adjust the energy charges in the rate structure as close as possible to normal costs based upon a specific price of fuel on which the existing rates are structured, and, for the time being at any rate, to allow the fuel clause to provide any needed and prompt adjustment of rates without the Board's direct intervention. The Board will however require that the correction factors to be applied when there is a change in the cost of fuel shall be notified to the Board and filed in advance of the issue of the bills embodying these factors.

It is to be observed that out of a total of $10,869,000, the estimated cost of fuel to the Company in 1974, it is estimated that $9,045,000 will be recovered in revenue from all consumers b[y] virtue of the Fuel Clause adjustment.

The Board will keep a close look at the cost of fuel and the effect of the Fuel Adjustment clause as it applies to various classes of consumers and may make adjustments whenever it deems appropriate.

Domestic category subsidy.

The Board has therefore reviewed the rate design which t[he] Company has submitted principally to ensure that the rate schedule[s] are fair and reasonable and that the burden is not unfairly allocated between the various classes of consumers.

It is clear from the evidence, that hitherto, the domestic consumer has not borne the cost of service provided by the Company. Indeed the Company was providing this service to the domestic user at a loss of 0.8 cents per kilowatt hour sold. All other consume[rs] bore their cost of service and subsidised the domestic consumers' cost. In the rate schedules proposed by the Company, the net profi[t] on the cost of service in cents per KWH sold will be distributed as follows - Domestic consumers 0.40, General service 5.51, Secondary Voltage Power 2.57, Large Power 2.37 and Street Lighting 3.41. The Board considers this an equitable distribution of the cost of

service

service between the various classes of consumers.

The Board notes that the Company's employees have been receiving a special rate for electric service of 3 cents per KWH. The proposed increase to 4 cents per KWH as shown in the tariff costs analysis 1974 (Exhibit 15) shows that the Company would sustain a loss of approximately 3 cents per unit on kilowatt hours supplied to employees. The Board allows the employee rate to continue but suggests that such rate should be not less than the lowest rate applicable to other custome rs, that is to say, 5 cents per kilowatt hour.

Subject to this the Board therefore approves the rate schedules proposed by the Company and orders that the rates there contained shall take effect in respect of all electric service supplied on and after March 1, 1974.

APPENDIX B

OVERHEADS APPLIED TO VALUATION OF ELECTRIC UTILITY PLANT AND PROPERTY AS OF DECEMBER 31, 1972, BY INTERNATIONAL MIDDLE WEST SERVICE COMPANY

	OVERHEAD PERCENTAGES (SEE NOTE BELOW)
Land	
Substations	18.1
Pole Yard	18.1
Residential	7.0
Garrison Hill	37.1
Spring Garden	35.1
Bush Hill	7.5
Steam Plant	
Unit A	25.0
Unit B	25.0
Transformers	16.0
Diesel Plant	
Garrison Hill	24.0
Spring Garden	24.0
Distribution Plant	
Substation Buildings	20.0
Substation Equipment	20.0
Poles	23.0
Overhead Conductor & Cable	23.0
Underground Cable	23.0
Line Transformers	16.0
Services	9.0
Street Lighting	23.0
Meters	9.0
General Plant	
Buildings	
Residential	8.5
Other	18.0
Transportation Equipment	7.0
Office Equipment & Furniture	7.0
Tools and Work Equipment	7.0
Laboratory and Test Equipment	7.0
Communications Equipment	7.0
Miscellaneous Equipment	7.0

NOTE:

The overhead percentages varied for the different classes of property and included, where applicable, the stamp duty and expense of transferring land, engineering and supervision, administration and general expense, interest during construction and financing charges. The amount included for interest during construction depended upon the length of the construction period and upon the timing of construction completion required for each of the various classes of plant it was in scheduling completion of the entire plant and securing and connecting all consumers.

RATE BASE YEAR END 1974

		$	$
ASSETS			
Fixed Assets @ 31.12.73			52,963,000
Add			
(a) Surplus @ 31.12.72			7,476,054
(b) Net additions @ 31.12.74			17,104,000
Fixed Assets @ 31.12.74			77,543,054
Deduct			
(a) Plant not in use 1974		69,268	
(b) Residential assets disallowed		588,386	657,654
			76,885,400
LESS DEPRECIATION			
Depreciation reserve @ 31.12.73 ..		12,371,000	
Less depreciation over-provided for on surplus @ 31.12.72 (see Note 1) ..		1,073,807	
		11,297,193	
Add depreciation for 1973 @ 3.705% on surplus allowed		276,987	
Depreciation allowed to 31.12.73 ..		11,574,180	
Add depreciation provision 1974 ..		2,658,000	
		14,232,180	
Deduct depreciation over-provided for 1974 (see Note 2)		750,000	
		13,482,180	
Add depreciation for 1974 @ 3.705% on surplus allowed		276,987	
Depreciation allowed @ 31.12.74		13,759,167	
Deduct depreciation on fixed assets disallowed to 31.12.72	$22,657*		
for 1973 @ 3.705%)	24,366		
for 1974 @ 3.705%)	24,366	71,389	13,687,778
			63,197,622
ADD WORKING CAPITAL			
Current Assets		5,663,000	
Less Current Liabilities		2,815,000	
		2,848,000	
Less customer contributions		4,375,000	(1,527,000)
			61,670,622

NOTE 1: To arrive at depreciation over-provided for on surplus @ 31.12.72 take Fixed Assets @ 31.12.72 of $53,296,532, deduct fixed assets depreciated of $43,461,480 which gives depreciation at 31.12.72 of $9,835,052. Deduct this amount from depreciation provided @ 31.12.72 resulting in $1,073,807 over-provided.

NOTE 2: Included in depreciation provision for 1974 was $750,000 representing 3.705% of appraisal of surplus of $20,242,000 which surplus was reduced by the Board to $7,476,054.

*See Note Appendix D.

FIXED ASSETS NOT IN USE

	Fair Value (RCN less overheads)	Fair Value Depreciated
	$	$
Barbarees Building	5,912	1,478
Spooners Hill Building	3,080	770
Bank Hall Building	3,080	2,463
Dan Building	11,145	2,786
Holetown Building	9,801	8,331
	33,018	15,828
Bank Hall Land	828	828
Prospect Land	28,160	28,160
Kingston Land	5,943	5,943
	34,931	34,931
Substation Equipment (Bank Hall)	1,319	1,319
Total land, buildings and substations	69,268	51,682

See also Exhibit 6 for Company's residential assets disallowed.

Total depreciation on these assets is $22,657, of which $17,586 is in respect of land, buildings and substation equipment and $ 5,071 in respect of furniture in residential buildings.

1070

BARBADOS.

IN THE MATTER OF THE PUBLIC UTILITIES ACT (1953-31) and as amended.

AND IN THE MATTER of the proposed changes in rates of the Barbados Light and Power Company Limited.

Before the Public Utilities Board.

On the 14th day of March, 1974

ORDER

At a Public Enquiry into the proposed changes in rates of the Barbados Light and Power Company Limited, and upon hearing the evidence adduced on behalf of the Company, and UPON HEARING Mr. J.S.B. Dear, Q.C., Counsel for the Company,

IT IS ORDERED that the following rates become effective in respect of all electricity used on and after the 1st day of March, 1974.

1. DOMESTIC SERVICE: Monthly Rate:

Fixed Charges: $3.00 per month.

Energy Charge (subject to Fuel Clause Adjustment)

First 50 Kwhs	@ 10 cents per Kwh.
Next 250 Kwhs	8 " " "
All over 300 Kwhs	6 " " "
Minimum Bill	$3.00 per month.

Discount: 10% for payment within 15 days of issue of bill, but not applicable to Fuel Clause Adjustment.

2. GENERAL SERVICE: Monthly Rate:

Fixed Charges: $5.00 per month.

Energy Charge (subject to Fuel Clause Adjustment)

First 500 Kwhs	@ 10 cents per Kwh.
Excess	8 " " "
Minimum Bill	$5.00 per month.

3. SECONDARY VOLTAGE POWER: Monthly Rate:

Demand Charge: For Company-owned transformer(s) $4.00 KVA of Billing Demand.

For Customer-owned transformer(s) $3.00 KVA of Billing Demand.

Energy Charge (subject to Fuel Clause Adjustment)

First 50 Kwhs/KVA of Billing Demand	@ 8 cents per Kw
Excess	6 " " "

(P.T.O.)

The minimum monthly bill shall be the appropriate demand charge plus the charge for the first 50 Kwhs/KVA of Billing Demand, which monthly bill shall not be less than the equivalent of a Billing Demand of 5 KVA plus 1,000 Kwhs of energy at the appropriate rate.

4. LARGE POWER: Monthly Rate:

Demand Charge .... $3.00/KVA of Billing Demand.

Energy Charge (subject to Fuel Clause Adjustment)

First 50 KWH/KVA of Billing Demand	@ 7	cents	per	Kwh.
Next 200 KWH/KVA of Billing Demand	5½	"	"	"
All over 250 KWH/KVA of Billing Demand	5	"	"	"

Minimum Bill: The demand charge but for not less than 100 KVA of Billing Demand.

IT IS FURTHER ORDERED that the correction factors in relation to all consumers by virtue of the Fuel Adjustment Clause be applied, and when there is a change in the cost of fuel shall be notified to the Board and filed in advance of the issue of bills embodying these factors.

AND IT IS ALSO FURTHER ORDERED that the Order on the 27th day of February be revoked.

Chairman

Member

Member

1072

6

Fair Trading Commission

FUEL ADJUSTMENT CHARGE FINDINGS REPORT

Document No. FTC/URD/FACREP/0107 Date: 19 January 2007

FUEL ADJUSTMENT CHARGE FINDINGS REPORT

1. Introduction

This paper reports the findings of the Commission's investigation into the Fuel Adjustment Charge applied by the Barbados Light & Power Co. Ltd. (BL&P). The decision to conduct this investigation was based on

1. General concerns expressed by consumers that there was a lack of transparency in its application.

2. The obligation of the Commission under the provisions of the Utility Regulation Act CAP 282, to monitor rates and standards of service of regulated utilities.

The Commission held public consultations during September 2004 following which the Commission engaged the consulting firm of Castalia Strategic Advisors "Castalia" in January 2006 to review the application of the fuel adjustment charge. Background on the Fuel Adjustment Charge is shown in Appendix 1.

Fuel Adjustment Charge Consultation

The Commission initiated a consultation on September 13th, 2004. The process included the issuance of a consultation paper "Fuel Adjustment Charge", as well as the hosting of three (3) public forums which were held at the Alexandra School, Solidarity House and the Lester Vaughn School. Details of the issues discussed in the Consultation Paper and comments received during the consultation are included in Appendix 2.

During the consultations the main concerns of the respondents were that:

(a) revenue from the fuel adjustment charge may be contributing to the company's profits and

(b) the fuel adjustment charge may be higher than it should be due to the use of the more costly fuels for generation.

The Commission therefore sought to address these issues through a review and investigation of the fuel adjustment charge by Castalia. Accordingly, Castalia were required to inter alia, assess whether the current method of determining the fuel adjustment charge provides adequate revenue to cover fuel costs without allowing the company to earn additional revenue; and give an assessment of whether the company is using the most economic and efficient generation mix.

The following section gives further details on what was required of the consultants under the terms of reference.

2. Investigation of Fuel Adjustment Charge by Consultants

Under the terms of reference set out by the Commission, the consultants were required to:

- Evaluate the method used by the company to project sales and costs which are used in determining the fuel adjustment charge;
- Assess whether the current method of determining the fuel adjustment charge provides adequate revenue to cover fuel costs without allowing the company to earn additional revenue from this aspect of the tariff;
- Evaluate the company's present method of determining the fuel adjustment charge and assess the impact on stability to both company and consumers. Compare this impact with that anticipated through suggested alternative method(s);
- Suggest an alternative formula or method which is transparent to consumers and does not result in an over or under recovery of fuel revenue over an extended period; and
- Assess the impact of implementing a system where the fuel adjustment charge is maintained at a constant level over consecutive months.
- Give an assessment of whether the company is using the most economic and efficient generation mix;

3. Review of Consultants Recommendations

This section presents the recommendations and supporting rationale of the consultants regarding the issues explored in their final reports followed by the Commission's response to each recommendation.

a) Fuel Adjustment Charge and Efficiency

Castalia Recommendation

The amount that BL&P is allowed to recover through the fuel adjustment charge mechanism should be related to the efficiency of its operation.

This efficiency should be measured in terms of its heat rate and transmission and distribution line losses. If the company exceeds efficiency targets it could recover an amount greater than that which is allowed by the fuel adjustment charge. If efficiency targets are not met the customers would receive lower charges.

It is considered that such a method would encourage BL&P to strive for the highest possible efficiencies with the incentive of maximizing earnings. At the same time, if the company's efficiency is reduced they would obtain less revenue.

Commission Response

The Commission recognizes that the method suggested fulfils the objective of providing an incentive for the company to continuously strive for improvement. However if the targets are exceeded customers will actually pay a cost for fuel greater than the fuel adjustment charge, or conversely if targets are not met BL&P will gain less revenue through this charge. The latter may affect the company's ability to maintain the quality of service generally and continue the expansion of service as required.

In principle, the main difficulty with this recommendation is that ultimately the customer will be penalised financially for any increase in the efficiency of operations of the company. Making customers pay a fuel adjustment charge that is greater than the amount that the utility incurs in purchasing fuel will mean that the fuel adjustment charge would no longer be a pass through charge.

However, the merit of periodically monitoring the average heat rates and line losses is agreed and the Commission will implement targets in these areas to be assessed in a manner similar to the method of evaluating the overall standards of the company. The Commission and the BL&P will agree the targets and the Commission will require that the company provide a report if it repeatedly falls below the targets. The Commission will reserve the right to impose penalties on the company for continuous performance below the standards if an unsatisfactory explanation is given.

The Commission also considers that there should be a unit of measurement introduced to address cost efficiency. While heat rate measures are designed to ensure that the technical efficiency of the plant is optimum it does not address the issue of aiming for the lowest cost per kWh of production.

In the rate hearing of 1983 this aspect was considered through the setting of targets for an accumulated production ratio (APR) of 5%. The APR is a measurement of the production from the gas turbines as a fraction of the total production. Gas turbines at that time used the more expensive fuels so this measure was indirectly a measure of cost efficiency. Increased efficiency of the modern turbines, growth in peak demand and an increase in the types of fuels which may be used in these turbines now makes the APR inapplicable.

The Commission will investigate the use of new indicators which will be aimed at addressing issues of cost efficiency.

b) Smoothing

Castalia Recommendation

The smoothing mechanism currently employed by BL&P should be retained.

Castalia's analysis showed that the mechanism for smoothing using projections of costs and revenues has achieved the objective of reducing fluctuations and has not resulted in prolonged periods where the company has been in a position of over recovery, that is, where the funds collected exceed the cost of fuel. In fact Castalia has stated that "if anything the balance in the fuel adjustment charge account has tended to be an under-recovery."

Commission Response

The Commission concurs with the view that the smoothing mechanism currently in place has considerable merit and will therefore allow BL&P to continue using this method.

c) **Interest on over recovery**

<u>Castalia Recommendation</u>

BL&P should be required to pay interest on any over recovery of fuel cost.

The company should return to customers over recovery with interest in order to give back customers their investment at the same rate of return as BL&P is allowed.

<u>Commission Response</u>

The Commission will explore this suggestion further and in the process will evaluate whether the benefits to customers justify any increased administrative and accounting costs. The period over which any over recovery would be assessed will also need to be addressed.

The Commission will review the feasibility of the Castalia proposed mechanism and consider the use of any other alternative methods of calculating the fuel adjustment charge which may provide incentives for improved efficiency.

d) Removal of base fuel charge

<u>Castalia Recommendation</u>

The base fuel charge of 2.64 cents should be removed from the energy charge, and all the fuel charge should be incorporated in the fuel adjustment charge.

The removal of the entire fuel charge from the energy charge is favoured as it is simple and enhances transparency, since customers often feel that there are paying for fuel twice when aspects related to fuel appear in more than one part of the bill.

Castalia also raised the alternative option of placing more of the fuel charge in the energy charge. In such a scenario, the amount of the fuel charge that is in the energy charge would be determined based on today's fuel prices. This would mean that the fuel adjustment charges would be very small or even negative if prices fell below the average set. ?

Commission Response

The Commission accepts that placing all of the fuel charge in one component of the bill would be more transparent. The Commission also acknowledges the value of the alternative option, that more of the fuel adjustment charge be placed in the energy portion of the bill but the latter alternative would not increase the transparency of the system to the same extent as the first option suggested.

However, under the Utilities Regulation Act, any change in the principles (formula, methodology or framework) for determining the rates of BL&P would require a rate hearing. The Commission does not consider that it would be prudent to convene a rate hearing at this time to look at this isolated issue especially as neither of the two actions proposed above is expected to affect the magnitude of the bill. The Commission may consider the feasibility of implementing the Castalia proposed mechanism at a later date when other aspects of BL&P operations and tariffs are being examined.

e) Competitive Procurement of Fuel

Castalia Recommendation

BL&P should review the process by which the contract for supplying fuel to BL&P is determined.

Discussions with BL&P revealed that they purchase fuel from BNOCL. There is therefore uncertainty regarding whether BL&P is currently obtaining fuel at the lowest available cost.

Commission Response

This issue is currently being investigated by the Fair Competition Department of the Commission.

f) Publishing of Relevant data

Castalia Recommendation

BL&P should be required to publish in detail the method of determining the fuel adjustment charge.

This should include monthly publication in the local newspapers of costs and revenue which go into the calculations of the fuel adjustment charge. Quarterly reports should be published showing the degree of over and under recovery from the fuel adjustment charge. A public consultation on the fuel prices for BL&P is also recommended.

By publishing the information the transparency of the processes would be enhanced and likewise the acceptability of the fuel adjustment charge.

Commission Response

The Commission agrees that a public awareness programme should be initiated to enhance the understanding of the nature of the inputs which are used to generate the fuel adjustment charge. The Commission is of the view that summary data on which the fuel adjustment charge is set should also be made available by BL&P to the public upon request. The Commission will pursue this with the BL&P and place a sample of the calculation of the fuel adjustment clause on its website for information.

4. Commission Position

The Commission having conducted this review concurs with the consultant's finding that "there is no evidence that BL&P has been systematically over recovering." Even though smoothing includes projections, the Commission believes that the method now employed compares favourably with that prescribed by the Public Utilities Board in 1983. The reduction in fluctuations achieved by the new method, justifies its continued use.

Accordingly, the Commission endorses the recommendation of Castalia to maintain the current method of smoothing. The Commission will, however, intensify the monitoring of indicators related to the efficiency of the BL& P. The regulation of BL&P will therefore be extended to include monitoring of heat rates and line losses. Monitoring of other indicators relating to cost efficiency will also be considered in the long term.

The Commission recognises that even though the current method adequately achieves the regulatory objectives of equity for consumer and the company, it is necessary to continue to explore alternatives which may be more appropriate in the future. The Commission will continue to work with the BL&P in this regard.

APPENDIX 1

Background on Fuel Adjustment Charge

The cost of providing electricity service to customers is affected by the fluctuation of oil prices on the international market. Since the cost of fuel is one of the main inputs in establishing the cost of electricity, the volatility of oil prices can have the effect of creating considerable uncertainty over the price.

The fuel adjustment charge eliminates the need for a rate hearing to be conducted every time there is a change in the cost of fuel. Through this mechanism the changes in cost of the fuel are passed through to consumers.

<u>Method used by the BL&P</u>

In the decision issued by the PUB in 1983, the fuel adjustment charge applied each month was set based on the over recovery/under recovery from the preceding 2 months.

The company has however made modifications to the system in the following way:

1. the fuel cost for each month is based on projections rather than purely on the over or under recovery of the previous months; and
2. The over recovery is maintained as a line item on the balance sheet but is not directly added or subtracted from the fuel cost of the month following.

The company wrote to the PUB in 1985 justifying the change on the basis that the new method produced less dramatic changes month to month and was therefore less of a burden on customers and the company from an accounting standpoint.

The information submitted monthly to the Commission gives an indication of the over and under recovery position of the company.

APPENDIX 2

Fuel Adjustment Charge Consultation

Issues Raised in Consultation paper

The Commission initiated a consultation on September 13th, 2004. The process included the issuance of a consultation paper[1] as well as the hosting of three (3) public forums which were held at Alexandra School, Solidarity House and Lester Vaughn School.

In the consultation paper the Commission outlined its position on the following issues:

1. Alternative Methods of Regulating Fuel Charge

In all electricity utilities which have cost of service regulation there needs to be a mechanism whereby the company can recover at least part of the increases in cost that they incur when there is an increase in oil prices. At times this is done by setting a variable fuel charge which may be modified periodically. In other instances the additional charge is reported as a separate line item with its own KWh charge.

Below are general advantages and disadvantages of the use of a Fuel Adjustment Charge.

Advantages

1. Allows company to recover any changing costs in fuel, allowing for greater stability, this is important to investors in the utility and the overall viability of the system; and

[1] FTC Consultation Paper Fuel Adjustment Charge, Document No. FTC/CONS04/04

2. Allows for changes to occur in tariffs from month to month without the necessity of engaging in rate hearings. This therefore reduces the regulatory cost.

Disadvantages

1. The system is not always transparent to customers / regulators; and
2. Over collection is not necessarily resolved on the following month or months to arrive at net value of zero.

2. Method of Fuel Adjustment Charge Application

The Commission recognises that the method adopted by the Barbados Light & Power Co. Ltd. reduces the spikes and thus reduces the effect of large monthly changes. However the system employed needs a level of transparency and this could be increased if the Commission is required to receive relevant information on choice of generation fuels.

Reconciliation – Alternative Applications

The Commission presented three alternative applications to the BL&P fuel adjustment charge; each example differed in the period over which reconciliation occurred.

- Monthly adjustments (Regulated Industries Commission, Trinidad & Tobago)
- Six month Reconciliation (Public Service Commission, Kentucky, U.S.A.)
- Annual Reconciliation (Public Utilities Commission, Texas, U.S.A.)

The Commission recognises that shorter reconciliation periods may increase fluctuations whereas longer reconciliation periods may increase the time where the company is in significant over or under recovery.

3. Generation Mix and Accumulated Production Ratio (APR) Requirement

The generation mix of the company significantly affects the cost of fuel used in producing electricity and thus determination of the level of the fuel adjustment charge. The monthly generation mix is determined by the maintenance needed on generation equipment, scheduled and unexpected, as well as the choice of generation technology that the company makes in planning for expansion. In recognition of this, the PUB in 1977 established a limit to the use of gas turbines which were less fuel efficient and used more expensive fuel for operation. The gas turbines were not to be responsible for more than 5% of the electricity generated per month from all generation. This variable in the generation mix was defined as the Accumulated Production Ratio (APR).

Decisions regarding the best way to use existing plant are currently made by the management of BL&P who have a level of expertise in this area. It is, nonetheless also critical to establish that the company demonstrates due diligence in maintaining its plant and equipment to ensure that customers are not unduly disadvantaged when base plant load machinery is out of use.

The Commission realises that with oil prices still being unpredictable a mechanism where the company can recover these increased costs is essential. There however needs to be an incentive to encourage the company to continually strive for the least cost fuel options. The APR level of 5% does not appear to be relevant given current technology but the Commission is of the view that there still needs to be some indicators set that allow the Commission to adequately monitor the efficiency of the company.

Responses to Written Consultation

The Consultation paper after setting out the Commission's concerns asked for responses from the public on specific questions and gave the opportunity for comments. The public forum also allowed for general comments on all relevant issues. Below is a summary of responses from these processes.

Q1. What are your views on the method currently used by BL&P to set the fuel adjustment charge? Do you have any suggestions for an alternative method?

One respondent was of the view that a six month or one year reconciliation should be used to make sure that the company is not maintained in an over recovery situation. Another respondent considered that the six month reconciliation similar to that used in Kentucky U.S.A. was the most appropriate.

Four respondents including the Barbados Chamber of Commerce (BCCI) considered that actual costs of fuel should be used rather than projections made by the company.

Barbados Light & Power are of the view that the current method benefits customers by reducing monthly fluctuations in the costs. The company has stated that the change in mechanism from the one proposed by the PUB was adopted after concerns expressed by consumers.

Q2. Do you have any suggestions for an alternative to the Fuel Adjustment Charge that can be applied?

One respondent considered that cost of fuel should be included in the operating cost of the company and customers should be charged a fixed price for unit of energy used. Two respondents were of the view that domestic customers should be exempted from the fuel adjustment charge, as had been the case before 1974.

With regards to other jurisdictions that did not use a fuel adjustment charge, the company believed that this was because these jurisdictions were not as dependent on petroleum based products as Barbados. BL&P therefore did not consider that an alternative to the fuel adjustment charge would be appropriate for Barbados.

Q3. Do you consider that the APR limitation of 5% should be enforced on the company by the Commission? Give reasons

The BCCI suggested that the 5% limit should be maintained in order to ensure that the company continued to seek the most efficient use of plant and fuels. BL&P did not consider that the 5 % APR was realistic considering the current generation mix and should therefore not be enforced. The company added that they expected the APR to be reduced below 10% when the new low speed diesel plant was installed.

Q4. Do you have any alternative suggestions of a mechanism to ensure efficiency of fuel use?

The BCCI considers that efficiency could be improved if the most efficient fuel mix possible was determined. The fuel adjustment charge would be based on the cost of fuel of most efficient fuel mix, in order to encourage the BL&P to move towards this.

Q5. Do you consider that BL&P should be required to submit the maintenance schedule for generation plant to the Commission?

The BCCI are not of the view that maintenance schedules should be shared with the Commission as this interferes with the responsibilities of the company management.

BL&P considered that the submission of the generation statistics was more useful than maintenance schedules since these may need to be modified from time to time.

Q6. Do you consider that the company should be required to submit projections of prices of fuel inputs periodically and the methodological basis of these to the Commission?

BCCI were of the view that the company should submit periodically both actual and projected fuel prices to the Commission.

BL&P is in agreement with submitting the projections it uses which are based on recent fuel prices and trends.

Other Issues Raised at Public Forum

1. Generation Plant

One respondent was of the view that the company decided on more expensive plant in order to increase profits.

He suggested that BL&P should rebate customers since high fuel adjustment charges is a result of their error in installation and technology choices. He was of the opinion that low speed diesels should have been installed 12 years before.

It seemed to the respondent that shareholders benefit from profits while customers pay for losses. He added that energy savings are generally not passed on to consumers.

2. Other Charges

One consumer was concerned that the fuel adjustment charge might contain other "hidden" charges which may contribute to the overall profits of the company.

Another consumer was of the view that the Commission should also investigate how other fixed charges are determined which may affect the electricity charge. If the company is over collecting in these areas this would reduce the amount of fuel adjustment charge that should be applied

3. Use of Jet Fuel

Two respondents wondered why jet fuel was chosen by the company as a generation fuel and why the use of natural gas was not considered in its place. Two respondents expressed concern that the gas turbines operated by jet fuel may be being used to provide baseload power.

4. Public Hearing

Two respondents suggested that a public hearing should be conducted by the FTC into the fuel adjustment charge.

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The Barbados Light & Power Company Limited

Annual Report 1986

75 years of progress through electricity 1911-1986

Rehabilitation work done on the administration building and additions that were completed in 1986 provided the staff with a comfortable ambience in which to work more efficiently.

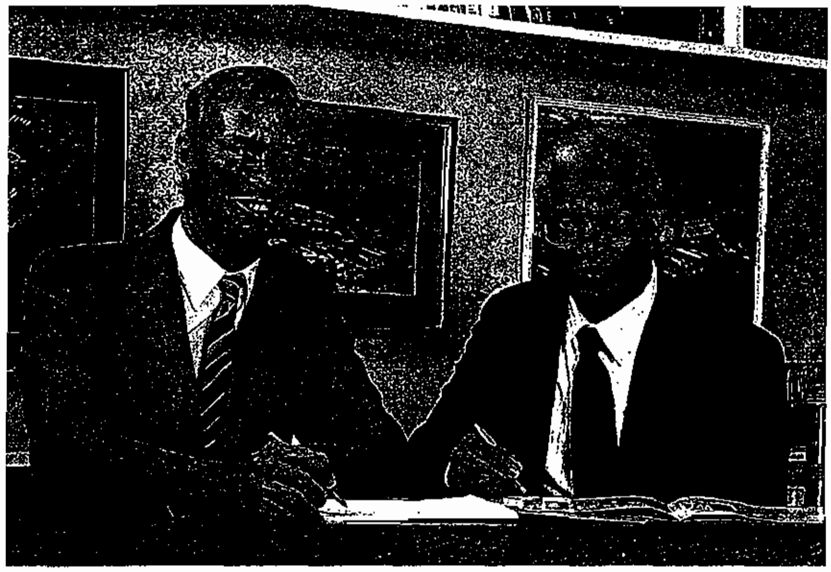
Operations

The expansion and improvement programme, which was started in 1981 and which has been completed at a cost of $140 million, contributed substantially to the reduction in electricity prices. The newest generating units use the low grade residual fuel which is much lower in cost than diesel fuel.

While the cost of this fuel has been falling with the fall in oil prices generally, the cost to the Company does not fall by the same amount as the fall in the price of crude oil. Possibly the price of residual fuel may increase in 1987 in view of the recent action by OPEC reducing its production.

Negotiations for a new labour contract were concluded during April and a three-year agreement was signed with effect from July 1st, 1985.

A number of electric utilities in the U.S. are establishing mutual insurance companies to provide self coverage because they are unable to purchase insurance from traditional sources to cover certain risks. The similar difficulties the Company experienced, with respect to insurance against the risk of hurricane, are in the process of being resolved. During the year, competitive bids were invited and J. H. Minet of London were appointed as the Company's insurance brokers.



Mr. Andrew Gittens and Mr. Alfred H. Clarke, elected to the Board of Directors.

Board of Directors

We regret that Sir Kenneth Hunte relinquished his seat on the Board of Directors in May 1986, after 31 years of service to the Company as a Director. Sir Kenneth is one of Barbados' outstanding business entrepreneurs and our Company is indebted to him for his wise counsel over the years.

In December, the Directors decided to fill two vacancies on the Board. Mr. Alfred Clarke Q. C. and Mr. Andrew Gittens kindly allowed their names to go forward for nomination and they were duly elected. Mr. Clarke is one of the Company's Attorneys at Law. Mr. Gittens, now the Company's Engineering Manager who started work with the Company in 1962, is a Chartered Electrical Engineer and Fellow of the British Institution of Electrical Engineers. The Company is fortunate that these two gentlemen have consented to join the Board.

Acknowledgements

We acknowledge with gratitude the many letters of congratulations which have been received from customers and community leaders during our 75th Anniversary Year.

Also, many contributions to our 75th Anniversary Programme were freely given by employees who are very proud of their Company. They promptly seized the opportunity to participate in various events some of which are pictorially illustrated in this report.

The Directors express their appreciation to all the employees for their fine performance during the past year without which the

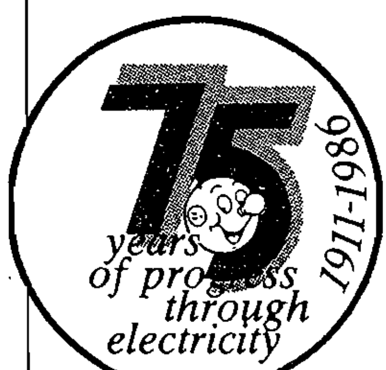
The exhaust stack at right marks the location
of the third low speed diesel unit at Spring Garden.

success of the Company would not be achieved.

During our special year, we reflected with pride on our past accomplishments. In 1987 we look forward with confidence to the future.

FOR THE BOARD OF
DIRECTORS

FRANK O. McCONNEY
Managing Director
February 5, 1987



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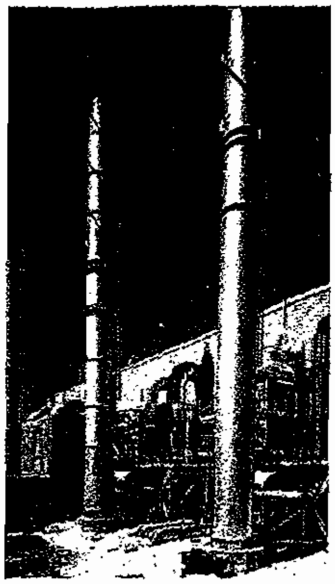
THE BARBADOS LIGHT & POWER COMPANY LIMITED

ANNUAL REPORT 1993



Directors' Report to the Shareholders

• Sales Record

Electricity sales increased 2.6 per cent from 499 million kilowatt hours (kWh) in 1992 to 512 million kWh in 1993. The growth in 1993 sales is attributable to a modest improvement in economic conditions with consumption among non-domestic customers growing by 2.1 per cent. The non-domestic customer classes accounted for 67.5 per cent of the electricity used by all customers in 1993. Residential sales increased by 3.5 per cent over 1992, reflecting a small increase in the number of new domestic customers and customers generally making greater use of electrical appliances.

Linesmen at work outside the recently renovated compound in Holetown that will house new premises for the Royal Barbados Police Force and Law Courts for the parish of St. James

• Electricity Price

During the year, the average price of electricity decreased from the December 1992 level. For example, residential customers paid $27.83 for 100 kWh of electricity in December 1993 compared to $31.55 for the same electricity consumption in December, 1992.

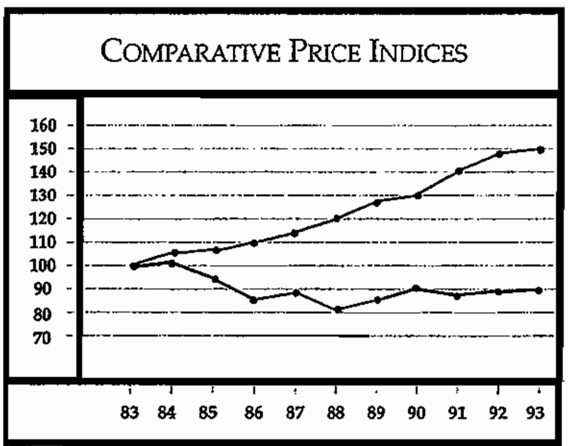
Although inflation, as measured by the retail price index, grew 49 per cent during the last decade, the price of electricity decreased by 10 per cent. In economic terms, this means the real price of electricity actually decreased by 40 per cent since 1983.

• Operating Results

The increase in sales contributed to an increase in 1993 revenue to $153.8 million. The greater part of the revenue collected from customers went to the Company's suppliers, with the largest payments, totalling $ 58.5 million, going to the fuel suppliers. Substantial payments were also made for labour, materials and spare parts in operating and maintaining the electricity system.

The Company's lenders received 13 per cent of the revenue collected as payments of principal and interest on loans. Shareholders received 3.5 per cent of the revenue in dividends.

The Company's earnings per share showed a marginal increase from 29.6 cents in 1992 to 30.5 cents in 1993. The market price for the common stock increased from $5.00 in December 1992 to $5.70 per share in December 1993. This increase in share price may be attributed to declining bank interest savings rates which fell from a high of 7 per cent to a low of 4 per cent in 1992. The rate is now 5 per cent. The interest rates on the Company's existing term loans are of course not variable.



The price of electricity has remained constant over the last ten years whilst retail prices have climbed considerably.

Catastrophic loss insurance was the primary expense affecting the Company in 1993. With insurance premiums rising from $700,000 in 1982 to $2.7 million in 1992, the Company's brokers estimated premiums would increase to the incredible amount of $9 million in 1993. Even so, the brokers were unable to find an insurance company to cover the transmission and distribution lines, which left the Company, like other Caribbean electric utilities, vulnerable in the event of a hurricane. To remedy this situation, the Company is negotiating an insurance plan for risks that presently are not acceptable in the traditional insurance market. To meet the additional cost of the insurance plan, a provision of $4.2 million has been made in the 1993 accounts. Mainly because of the escalation in insurance costs, non-fuel operating expenses increased by 7.2 per cent from $41.2 million in 1992 to $44.2 million in 1993.

With an increase in fuel prices in 1992, fuel costs were relatively high in the first half of 1993. However, when prices fell towards the end of the year, customers automatically benefitted since the fuel charge on customer electricity bills drops when the cost of fuel, to generate electricity, goes down. In addition, the Company continued to optimise its use of fuel in 1993 by producing 93.4 per cent of the island's electricity by using the generating plant that burns the most economical low grade residual fuel available.

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HURRICANES OF 1955

GORDON E. DUNN, WALTER R. DAVIS, AND PAUL L. MOORE

Weather Bureau Office, Miami, Fla.

1. GENERAL SUMMARY

There were 13 tropical storms in 1955, (fig. 9), of which 10 attained hurricane force, a number known to have been exceeded only once before when 11 hurricanes were recorded in 1950. This compares with a normal of about 9.2 tropical storms and 5 of hurricane intensity. In contrast to 1954, no hurricanes crossed the coastline north of Cape Hatteras and no hurricane winds were reported north of that point. No tropical storm of hurricane intensity affected any portion of the United States coastline along the Gulf of Mexico or in Florida for the second consecutive year. Only one hurricane has affected Florida since 1950 and it was of little consequence. However, similar hurricane-free periods have occurred before.

Namias and C. Dunn [1] have advanced a hypothesis for the above-normal frequency of hurricanes in 1955:

. . . planetary wave forms over the North Atlantic evolved in a manner which the authors have come to associate with tropical storm formation. Thus in late July the ridge of the Azores upper level anticyclone thrust strongly northeastward into Europe, thereby introducing a northeasterly flow which, through vorticity flux, led to an anomalously sharp and deep trough extending along the Spanish and African coasts. It was probably at the base of this trough that Connie developed—its formation encouraged by the injection of cyclonic vorticity from the north and by associated vertical destabilization processes as discussed in an earlier report [2]. If this hypothesis is correct, the frequency of tropical storms of the Cape Verde type may well depend upon the degree of development or suppression of the protruding Azores ridge to the north.

It is interesting to note that Garriott [3] almost 50 years ago, with no upper air data, gave a strikingly similar explanation:

Tropical storm development was exceptionally active in American waters during September 1906. In seeking the causes of this activity, we find an apparent contributory condition in the distribution of atmospheric pressure over the region of observation. In the West Indies and adjacent waters barometric pressure was unusually low, while in the more northern latitudes of the Atlantic, and more especially from the Azores over the British Isles, the barometer averaged above normal, and after the 17th was remarkably high. This arrangement of air pressure overlying the Atlantic naturally produced an unusually strong flow of air from the more northern latitudes toward the Tropics, and in this accelerated movement of air currents is found a recognized associated cause of tropical storm development.

The 1955 hurricanes showed a preferred area of development to the east of the Antilles and to some extent a grouping in their paths. The three hurricanes entering the United States all crossed the North Carolina coast within a 6-week period and three more crossed the Mexican coast within 150 miles of Tampico within a period of 25 days.

The hurricane season of 1955 was the most disastrous in history and for the second consecutive year broke all previous records for damage. Hurricane Diane was undoubtedly the greatest natural catastrophe in the history of the United States and earned the unenviable distinction of "the first billion dollar hurricane". While the Weather Bureau has conservatively estimated the direct damage from Diane at between $700,000,000 and $800,000,000, indirect losses of wages, business earnings, etc., would bring the total over one billion dollars. The total loss of life and damage from Atlantic hurricanes in 1955 is estimated by the Weather Bureau at 1,518 or more killed and $1,053,410,000 damage of which 218 fatalities and $889,310,000 occurred in the United States. The figures for total damage are admittedly incomplete. The latest United Press tabulation of damage at time of preparation of this article was $1,680,200,000 in the United States and $401,200,000 outside the United States, which adds up to a staggering total in excess of two billion dollars. The number of 1,518 or more killed in and outside the United States is the greatest since 1942 when the Weather Bureau began recording this datum.

2. INDIVIDUAL HURRICANES

The individual hurricanes of 1955 are summarized briefly and Connie, Diane, and Janet are discussed in some detail. For additional data, readers are referred to *Climatological Data, National Summary*, Annual 1955 (not yet released).

Alice, December 30–January 6.—A low pressure system of extra-tropical or tropical nature was noted some 600 miles northeast of the Leeward Islands on December 30, and on January 1 it reached hurricane intensity with definite tropical characteristics. It moved on a west-southwestward course passing through the Leeward Islands on January 2. An estimated wind of 75 m. p. h. was reported at St. Kitts and the last observation from St. Barthélemy indicated wind speeds ranging from 69 to 81 m. p. h. Winds of hurricane intensity were observed

1104 damage, excluding crop damage, in this area, is a tribute to the effectiveness of the warnings and precautionary measures taken by governmental and private agencies such as the Red Cross.

After crossing the coastline, Ione recurved to the northeast passing out to sea south of Norfolk, Va.

Janet, September 21–29.—Most of the easterly waves in which hurricanes developed during the months of August and September could be traced back to the Cape Verde Islands. However, at about the time the easterly wave in which Janet eventually formed should have passed through the Cape Verdes, receipt of reports from this area was so irregular that no early history of the wave is available. Early on the 21st, pilot reports from the airlines Air France and Iberia indicated the presence of a weak tropical disturbance at about Latitude 13.5° N. and Longitude 53.0° W. It is the experience of the Miami Hurricane Center that almost all tropical storms of hurricane intensity, and the great majority of minor tropical storms as well, cannot pass across the New York-Capetown shipping route without detection. Apparently the wave was too weak to be noted between Longitudes 40° and 50° W. Therefore, it is believed that Janet was just attaining hurricane intensity when encountered by the *SS Mormacdale* in Latitude 13.6° N. and Longitude 55.2° W. at 1900 EST on September 21 when it reported winds of 63 m. p. h.

The eye of hurricane Janet passed just south of the island of Barbados shortly after 1100 EST on the 22d. It was an immature hurricane at this time with a very small ring of hurricane winds around the 20-mile eye. The reconnaissance plane reported the wall cloud around the eye only 5 miles wide but turbulence was very severe. Maximum winds were estimated by an observer on the south side of the island at 110 to 120 m. p. h., dropping off very rapidly 20 miles out from the edge of the eye. The rapid increase in winds is illustrated by the following observations taken at Evanman, Maxwells Court, Christ Church, by Mr. H. W. Webster.

Time (AST)	*Speed* (*m. p. h.*)	*Direction*
10:45 a. m.	43	
11:00 a. m.	58	
11:15 a. m.	62	
11:20 a. m.	64	
11:24 a. m.	66	Wind mostly north to north-northeast
11:28 a. m.	70	
11:37 a. m.	72	
11:39 a. m.	82	
11:40 a. m.	90	
12:06 p. m.	50	East
Lowest barometer 29.20 inches, or 989 mb., sky brightening south, eye passing to south		
12:20 p. m.	100+(110–120)	East-southeast

No further data are available but the storm subsided quite rapidly.

The hurricane was moving at 11 m. p. h. at this time so it can be seen the ring of hurricane winds was very narrow. The lowest pressure reported by plane in the eye just to the south of the island was 979 mb. (28.91 inches). This was the first hurricane in Barbados in 57 years. The storm passed between Grenada and Carriacou early on the 23d. Fatalities in Barbados numbered 38 and in the Grenadines 122. Property damage was in excess of $2,800,000.

During the next several days in the eastern Caribbean, Janet pursued a course generally toward the west with some actual decrease in intensity. The center was located at 3:00 p. m. on September 23 at Latitude 13.2° N. and Longitude 64.8° W. with central pressure 996 mb. (29.41 inches) and wind 92 m. p. h., radar eye 40 miles in diameter, and wind eye 20 miles N–S, 27 E–W. Turbulence was moderate, sea high, no weather bands in northern semicircle but some in the southern semicircle.

During the early hours on the 24th, according to the Navy reconnaissance plane, Janet never presented good center definition and it is not certain the center was found. Weather targets consisted of large areas of diffuse targets with no spiral relationship. All center fixes were taken on strongest, most promising targets and the plane stated the fixes were of unknown accuracy. The radar bands were so disorganized, radar coverage was not considered feasible. Late in the afternoon, one very strong spiral weather band was found although the central pressure remained about the same. The reconnaissance plane reported:

Eye centered Lat. 13.8° N. and Long. 69.9° W. at 3:02 p. m., EST, circular eye with well defined cloud and wind eye approximately 20 miles in diameter. Minimum pressure 29.38 inches, or 995 mb., maximum wind 127 m. p. h. . . . in weather band 40 miles from eye in southwest quadrant, wind shifted in weather band from 240° to 330°, band approximately 25 miles thick, section we went through showed up weakest on radar, maximum winds northwest through southwest 52 m. p. h., turbulence light to none except in weather band where it was moderate to heavy, precipitation light to none, navigation good, radar coverage not considered feasible for eye positions, however, weather band to west presents good picture.

On the 25th the eye was located at 1400 EST at Latitude 14.3° N. and Longitude 74.2° W. with a maximum wind of 98 m. p. h., central pressure 987.7 mb. (29.17 inches). The eye was described as well defined but there was evidence it was very changeable—hoop-shaped on one occasion, a figure "6" on another. One obtains the impression of a slowly but definitely intensifying storm. The reconnaissance flight on the night of September 25–26 summarizes its observations as follows:

Eye completely closed circle after 9:15 p. m., average diameter 22 miles, storm presented symmetrical pattern of intense weather bands which extended 120 miles south, 140 east, 130 north, and 170 west, high overcast throughout area, low scattered to broken stratocu with tops near 6000, thunderstorms generally oriented in spiral bands throughout area, frequent lightning.

Rapid intensification was evident.

At 0830 EST of the 26th, Lt. Comdr. Windham with crew of 8 and 2 newspapermen reported in Latitude 15.4° N. and Longitude 78.2° W. that they were about to begin penetration of the main core of the storm. No further report was ever received from this plane. Janet had become a very severe hurricane.

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Tropical Cyclone Report
Hurricane Ivan
2-24 September 2004

Stacy R. Stewart
National Hurricane Center
16 December 2004
(updated 27 May 2005)

Ivan was a classical, long-lived Cape Verde hurricane that reached Category 5 strength three times on the Saffir-Simpson Hurricane Scale (SSHS). It was also the strongest hurricane on record that far south east of the Lesser Antilles. Ivan caused considerable damage and loss of life as it passed through the Caribbean Sea.

a. Synoptic History

Ivan developed from a large tropical wave that moved off the west coast of Africa on 31 August. Although the wave was accompanied by a surface pressure system and an impressive upper-level outflow pattern, associated convection was limited and not well organized. However, by early on 1 September, convective banding began to develop around the low-level center and Dvorak satellite classifications were initiated later that day. Favorable upper-level outflow and low shear environment was conducive for the formation of vigorous deep convection to develop and persist near the center, and it is estimated that a tropical depression formed around 1800 UTC 2 September. Figure 1 depicts the "best track" of the tropical cyclone's path. The wind and pressure histories are shown in Figs. 2a and 3a, respectively. Table 1 is a listing of the best track positions and intensities.

Despite a relatively low latitude (9.7° N), development continued and it is estimated that the cyclone became Tropical Storm Ivan just 12 h later at 0600 UTC 3 September. Ivan continued on a generally westward motion south of 10°N latitude and steadily strengthened, becoming a hurricane at 0600 UTC 5 September centered about 1000 n mi east of Tobago in the southern Windward Islands. After reaching hurricane strength, the rate of intensification increased dramatically and Ivan underwent an 18 h period of rapid intensification (rate $\geq$ 30 kt/24 h). Satellite intensity estimates suggest that the intensity increased 50 kt while the central pressure decreased 39 mb during that time and Ivan reached its first peak intensity of 115 kt at 0000 UTC 6 September. This made Ivan the southernmost major hurricane on record. However, almost as quickly as Ivan strengthened it also weakened -- as much 20 kt over the following 24 h. Conventional and microwave satellite data indicated the probable cause of the rapid weakening was due to mid-level dry air that got wrapped into the center of the hurricane and eroded the eyewall convection.

Immediately following the 24 h weakening period, Ivan began a second strengthening phase (Fig. 2b) that also contained a 12 h period of rapid intensification. During that time, Ivan was under surveillance by U.S. Air Force Reserve reconnaissance aircraft as the hurricane approached the southern Windward Islands. Reports from the aircrew indicated that Ivan had strengthened to a strong category 3 (SSHS) hurricane as the center passed about 6 n mi south-southwest of Grenada. The eye diameter at that time was about 10 n mi, and the strongest winds raked the southern portion of the island.

After passing Grenada and into the southeastern Caribbean Sea, the hurricane's intensity leveled off until 1800 UTC on 8 September when another brief period of rapid intensification system. In addition, extensive beach erosion caused severe damage to or the destruction of numerous beachfront homes, as well as apartment and condominium buildings. Some buildings collapsed due to scouring of the sand from underneath the foundations caused by the inundating wave action. Thousands of homes the three-county coastal area of Baldwin, Escambia, and Santa Rosa were damaged or destroyed. Cleanup efforts alone in Escambia County resulted in debris piles that were more than three-quarters of a mile long and 70 feet high. In all, Ivan was the most destructive hurricane to affect this area in more than 100 years. Strong winds also spread well inland damaging homes, and downing tress and power lines. At one point, more than 1.8 million people were without power in nine states.

In addition to the damaged homes and businesses, Ivan also destroyed millions of acres of woodlands and forests. The Alabama Forestry Commission found damaged timber valued at about $610 million on 2.7 million acres. These figures include

-- *Pine pulpwood*: 7.5 million cubic feet

-- *Hardwood pulpwood*: 2.6 million cubic feet

-- *Pine sawtimber*: 351.5 million board feet

-- *Hardwood sawtimber*: 493 million board feet.

In the 200,000-acre Blackwater Forest, just east of Pensacola in the western Florida panhandle, more than 1.5 million board feet of timber were downed across 185,000 acres.

Ivan's effects were not just limited to coastal and inland areas. Offshore oil industry operations in the Gulf of Mexico were severely disrupted, and several oil drilling platforms and pipelines sustained varying degrees of damage. The normal daily flow of 475,000 barrels of oil and 1.8 billion cubic feet of natural gas, plus refining operations, were disrupted for more than 4 weeks. A total of 12 large pipelines and 6 drilling platforms sustained major damage; another 7 platforms were completely destroyed.

A total of 686,700 claims were filed and the American Insurance Services Group estimates (14 December 2004 re-survey) that insured losses in the United States from Hurricane Ivan totaled $7.11 billion, of which more than $4 billion occurred in Florida alone. Using a two-to-one ratio of insured damages yields an estimated U.S. loss of approximately $14.2 billion. In addition to the insured losses that occurred, the U.S. Naval Air Station at Pensacola, Florida sustained damage losses of $800-$900 million.

In the Caribbean region, extensive damage occurred to homes, buildings and other structures. The following are brief synopses of the reports received from some of the Caribbean islands:

Barbados – More than 176 homes completely destroyed; many homes lost their roofs; most coastal roads severely damaged due to erosion caused by the storm surge and wave action.

Cayman Islands -- 95 percent of the homes and other buildings (which generally follow South Florida's building codes) were damaged or destroyed;

Cuba -- roofs were torn off homes in extreme western Pinar del Rio Province; flooding damaged houses, and fishing and farm installations; mud slides

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Statutory Instruments Supplement No. 44
Supplement to Official Gazette No. 70 dated 31st August, 1998

S.I. 1998 No. 91 (corrected copy)

Insurance Act
(Act 1996-32)

INSURANCE (BARBADOS LIGHT AND POWER COMPANY LIMITED) (SELF INSURANCE FUND) REGULATIONS, 1998

The Minister in exercise of the powers conferred on him by section 154 of the *Insurance Act*, makes the following regulations:

1. These regulations may be cited as the *Insurance (Barbados Light and Power Company Limited) (Self Insurance Fund) Regulations, 1998.*

2. In these regulations,

"castastrophe" means

(a) earthquake shock, fire resulting from an earthquake, or a flood caused by an earthquake;

(b) a hurricane, cyclone, tornado, windstorm or flood;

(c) an overflow of the sea onto Barbados, accompanying or caused by the elements listed in sub-paragraphs *(a)* or *(b)*; or

(d) any other peril approved by the Supervisor of Insurance.

"company" means the Barbados Light and Power Company Limited;

"Fund" means the self insurance fund established under regulation 3;

"investment grade securities" means securities which have received a credit rating of not lower than AA from a recognised credit rating Agency.

3. There is established a Fund for the purpose of self insuring the assets of the company that are listed in the Schedule against damage and consequential loss as a result of a catastrophe.

4. The Fund shall be created by deed of trust and the trustee shall be such persons as the Supervisor of Insurance shall approve.

5. The monetary limit of the Fund shall be

(a) the total of the replacement cost of the assets which are being self insured and the self insured portion of the company's commercial insurance programme; or

(b) 10 percent of the total assets of the company, where the replacement cost is not easily determined.

6. The maximum annual payment by the company to the Fund is

(a) 20 percent of the total replacement cost of the assets which are being self insured plus the self insured portion of the company's commercial insurance programme; or

(b) 5 percent of the total assets of the company, where the replacement cost is not easily determined.

7. The assets of the Fund shall not be mortgaged or assigned by the company.

8. (1) The Fund shall only be utilized by the company for the purpose of replacing or reinstating the self insured assets which are damaged by catastrophe and reinstating the financial loss following such damage.

(2) Where the Fund is utilized for any other purpose any monies withdrawn shall be subject to corporation tax.

9. The company shall submit to the Supervisor of Insurance, within four months of the end of each financial year of the company, an audited statement of the assets and liabilities of the Fund.

10. (1) Up to 60 percent of the Fund shall be invested in overseas securities on the condition that the securities are investment grade securities.

(2) The remaining 40 percent of the Fund shall be invested in securities in accordance with the *Insurance (Prescribed Securities) Regulations, 1998*. S.I. 1998 No. 73

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Statutory Instruments Supplement No. 9
Supplement to Official Gazette No. 19 dated 3rd March, 2005

S.I. 2005 No. 16

Insurance Act
Cap. 310

INSURANCE (BARBADOS LIGHT AND POWER COMPANY LIMITED) (SELF-INSURANCE FUND) (AMENDMENT) REGULATIONS, 2005

The Minister in exercise of the powers conferred on him by section 154 of the *Insurance Act* makes the following Regulations:

1. These Regulations may be cited as the *Insurance (Barbados Light and Power Company Limited) (Self-Insurance Fund) (Amendment) Regulations, 2005.*

2. Regulation 2 of the *Insurance (Barbados Light and Power Company Limited) (Self-Insurance Fund) Regulations, 1998* in these Regulations referred to as the principal Regulations, is amended by S.I. 1998 No. 91.

(a) inserting the words "volcanic eruption" immediately after the word "hurricane" appearing in paragraph *(b);*

(b) deleting paragraph *(c)* and substituting the following:

"an overflow of the sea onto Barbados from any cause;";

(c) renumbering paragraph *(d)* as paragraph (i);

(d) inserting the following new paragraphs immediately after paragraph *(c);*

"*(d)* fire, lightning, smoke damage;

(e) general impact, vehicle impact, or impact caused by aircraft or other aerial devices;

(f) riot, strike, terrorism, civil commotion, malicious damage;

(*g*) general explosion, boiler explosion, burst pipes;

(*h*) breakdown of electrical and other machinery".

3. Regulation 10 is amended in paragraph 2 by deleting the words "remaining 40 percent" appearing in the first line of that paragraph and substituting the word "remainder".

4. The *Schedule* to the principal Regulations is amended by deleting paragraph B and substituting the following:

"B. Generation Plant, Equipment, Buildings and other Contents of the Buildings".

Made by the Minister this 15th day of February, 2005.

O. S. ARTHUR
Minister responsible for Finance.

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CGM Gallagher Insurance Brokers (Barbados) Limited

2 March 2009

Mr Peter Williams
Managing Director
Barbados Light & Power Company Limited
The Garrison
St Michael

Dear Peter,

Re: T&D Insurance

Further to our discussions, I confirm that we have obtained some price indications for insurance on the T&D including hurricane/windstorm cover.

As I expected, these rates have not changed and are still at the level that was applicable when BL&P first decided to self insure the T&D.

Total Value At Risk		=	US$150 million
Option 1:	Loss Limit	=	$20 million
	Premium	=	$5.0 million
Option 2:	Loss Limit	=	$50 million
	Premium	=	$10 million

In order to give a reasonable comparison of the real cost of coverage, we asked for a relatively low deductible of $500,000. However, as I explained in previous reports on the T&D, the rate does not drop significantly if BL&P was to increase the deductible significantly.

(a) Deductible of $2.0 million
Premium above could be discounted by 10%

(b) Deductible of $5.0 million
Premium could be discounted by 25%

Please also note that the limit of coverage ($20M or $50M) is in aggregate. In other words, if it was fully used in the insurance period, we would have to purchase new insurance all over again.

Finally, our colleagues warned us that if we actually requested coverage, that the maximum they would be able to purchase at these prices would be in the range of $20 million.

Cont'd.../2

CGM Gallagher Insurance Brokers (Barbados) Limited
Haggatt Hall, St. Michael BB11059, Barbados
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CGM Gallagher Insurance Brokers (Barbados) Limited

2 March 2009

Mr Peter Williams
Managing Director
Barbados Light & Power Company Limited

The high commercial cost of T&D Insurance continues to justify the decision to self insure this exposure.

Kind regards,

William Tomlin
Director

WT/qf

cc Michael Tomlin – CGM Gallagher Insurance Brokers (Barbados) Limited
Martin Goddard – Carib Risk Managers (Barbados) Limited

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WM. COCHRAN KEATING IV, ESQUIRE, and KATHERINE FLEMING, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

FINAL ORDER APPROVING STORM COST RECOVERY SURCHARGE

BY THE COMMISSION:

I. BACKGROUND

On November 4, 2004, Florida Power & Light Company ("FPL" or "Company") filed a petition seeking authority to recover prudently incurred restoration costs, in excess of its storm reserve balance, related to the three major hurricanes that struck its service territory in 2004. In its petition, FPL asserted that as a result of Hurricanes Charley, Frances, and Jeanne, FPL estimated its extraordinary storm-related costs to be approximately $710 million, net of insurance proceeds, which would result in a deficit of approximately $356 million in its storm reserve fund at the end of December 2004. FPL proposed to recover $354 million of this estimated deficit through a monthly surcharge to apply to customer bills over a 24-month recovery period. According to FPL's petition, the amount that was in its storm reserve as of December 31, 2004 was approximately $354 million.

On November 19, 2004, FPL filed a petition seeking approval to implement its proposed surcharge on a preliminary basis, subject to refund, pending our final order in this docket. Along with its petition, FPL filed a tariff sheet reflecting its proposed surcharge by rate class. By Order No. PSC-05-0187-PCO-EI, issued February 17, 2005, we granted FPL's request to implement its proposed surcharge on a preliminary basis, and the preliminary surcharge became effective, subject to refund, for meter readings taken on or after February 17, 2005.

By Order No. PSC-05-0283-PCO-EI, issued March 16, 2005, we granted FPL leave to amend its original petition to reflect an updated estimate of the storm-related costs contained in its original petition. In its amended petition, filed February 4, 2005, FPL updated its estimate of extraordinary storm related costs to approximately $890 million, net of insurance proceeds, which would result in a deficit of approximately $536 million in its storm reserve fund at the end of December 2004. By its amended petition, FPL proposes to recover $533 million of this estimated deficit through a monthly surcharge to apply to customer bills based on a 36-month recovery period.

On April 6 and April 11-13, 2005, we held customer service hearings in Ft. Myers, Port Charlotte, Daytona Beach, Melbourne, Stuart, and West Palm Beach. On April 20 and 21, 2005, we conducted a technical hearing on FPL's amended petition. The Office of Public Counsel ("OPC"), Florida Industrial Power Users Group ("FIPUG"), Florida Retail Federation ("FRF"), Thomas P. and Genevieve E. Twomey ("Twomeys"), and AARP participated as Intervenors in

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's amended petition seeking authority to recover prudently incurred restoration costs related to the hurricanes that struck its service territory in 2004 in excess of its storm reserve balance is granted, subject to the adjustments and terms set forth in the body of this Order. It is further

ORDERED that, as a result of the adjustments discussed in the body of this Order, the appropriate amount of prudently-incurred storm-related costs to be charged against FPL's storm reserve is $794,309,025 (jurisdictional). It is further

ORDERED that, as a result of the adjustments discussed in the body of this Order, the appropriate amount of prudently-incurred storm-related costs to be recovered from FPL's customers through a surcharge is $441,990,525 (jurisdictional). It is further

ORDERED that FPL shall cease charging costs to its storm reserve no later than July 31, 2005, for restoration work related to the 2004 storm season. It is further

ORDERED that FPL shall record the unamortized balance of its 2004 storm-related costs subject to future recovery as a regulatory asset in a sub account of Account 182.1, Extraordinary Property Losses. It is further

ORDERED that FPL shall be permitted to charge interest on the unamortized balance of 2004 storm-related costs at the applicable 30-day commercial paper rate. It is further

ORDERED that FPL shall account for storm-related deferred taxes as set forth in the body of this Order. It is further

ORDERED that FPL shall revise its proposed storm surcharge factors based on the allocation methodology set forth in the body of this Order and shall immediately file revised tariffs reflecting the new factors, such tariffs to become effective with cycle 13 billings for September 2005. The factors shall be designed to recover the jurisdictional storm cost recovery amount approved herein, plus interest and revenue taxes, less the actual/estimated revenues collected between February 17, 2005, and cycle 12 billings for September 2005. It is further

ORDERED that FPL's revised storm surcharge factors shall be effective through cycle 12 billings for February 2008, unless all approved costs are recovered sooner, in which case the recovery period shall continue until the next cycle 12 billings. Within 60 days following expiration of this recovery period, FPL shall file for review and approval its final over-recovery or under-recovery of the approved costs and shall propose a method to address the final over-recovery or under-recovery. It is further

ORDERED that this docket shall be closed.

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