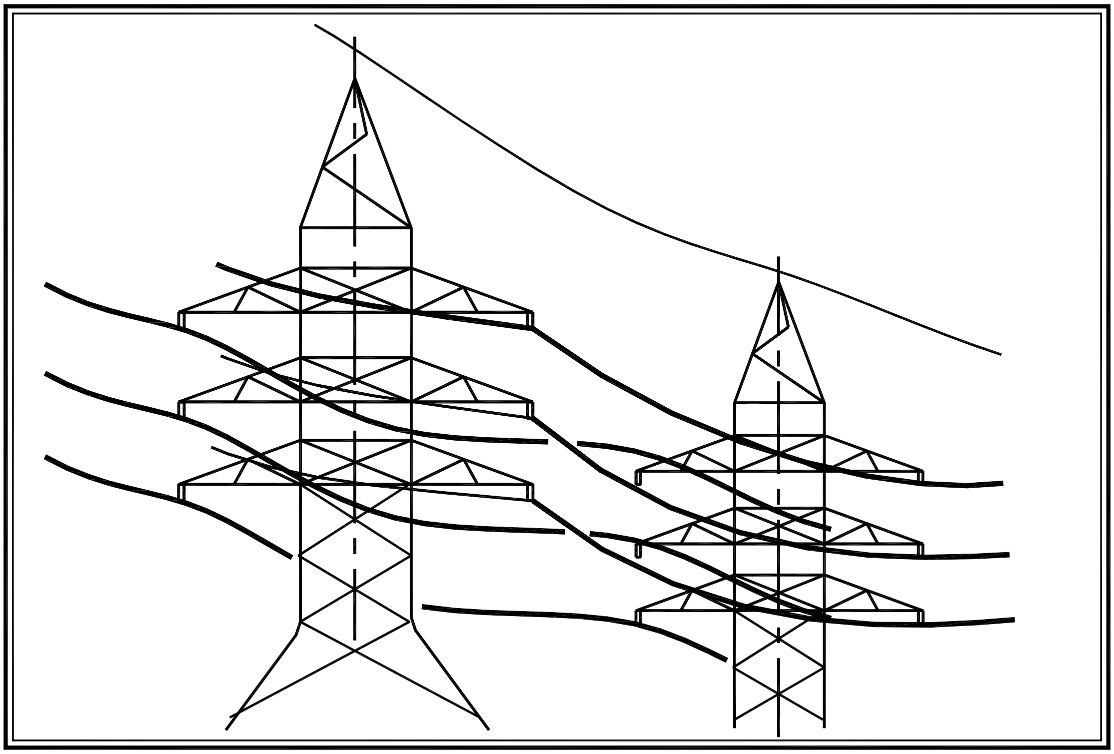


BUSINESS PLAN
2004-2008

TRINIDAD AND TOBAGO ELECTRICITY COMMISSION

T&TEC

BUSINESS PLAN 2004- 2008

1 EXECUTIVE SUMMARY

The document presents an overview of Trinidad and Tobago Electricity Commission (T&TEC) over the next five years of which the case for a tariff increase forms the major element. It first assesses the external environment in which T&TEC will operate over the next five (5) years. This environment consists of economic, customer, shareholder, regulatory, technological and health, safety and environmental factors. It is envisaged that the external environment would be favourable for the pursuit of T&TEC's objectives.

The business parameters, which will influence the outcome of T&TEC's endeavours, are then identified and explored. These business parameters include the legal framework, T&TEC's mission, vision, existing fixed assets, financial viability, generation capacity, transmission and subtransmission infrastructure, distribution infrastructure and human resources.

Two (2) of the elements of these business parameters have been found to contain certain risk and uncertainty factors that would affect T&TEC over the five year period. These are uneconomic Tariff Structures and Power Conversion Costs.

Based on the Cost of Service Study (COS) 2001, the revenue derived from residential and commercial and street lighting customers does not cover the cost of providing service to these groups. The overall loss for all customers was 4.4 cents per kWh in 2001. In order to manage this risk, T&TEC must obtain rates that cover its cost of service for all categories of customers and generate a fair rate of return to fund major capital expansion including the reinforcement of the existing transmission system, to prevent the occurrence of blackouts similar to that which occurred recently in North America and Europe.

With the imminent need to acquire extra capacity T&TEC will continue to seek favourable terms for additional power conversion.

This document then proceeds to identify five (5) key business issues that result from consideration of the external environment, business parameters and risk and uncertainty factors. Strategies for the realisation of these key business issues are then identified and discussed. These Strategies and their key associated elements are presented as follows:

- Continue to enhance the level of customer service
  - ⇒ Customer Call Centre
  - ⇒ Automatic Meter Reading
- Achieve a supply/demand balance in
  - ⇒ Generation and Transmission Capacity
  - ⇒ Distribution Infrastructure
- Maintain the network infrastructure and assets
  - ⇒ Work Order Maintenance System
  - ⇒ Reliability Centred Maintenance
- Continue to realize efficiency improvements
  - ⇒ Efficiency improvements in the last five (5) years
  - ⇒ Plans to improve operating efficiency
- Seek to obtain tariffs which would satisfy revenue requirements
  - ⇒ Price Limits based on true/full costs
  - ⇒ Price Limits assuming cross-subsidisation

In conducting the rate review exercise for 2004 to 2008 the appropriateness of the existing rate groups was considered. Given the need to more accurately place customers within a group that closely satisfies their particular characteristics of service, several new rate groups have been added. The proposed character of service rules for these new and existing rate groups can be seen in Appendix 23.

In addition to the aforementioned two (2) tariff scenarios have been included. The first scenario reflects a true or full cost of supplying electricity while the latter assumes a level of cross-subsidisation within and between rate groups, which is our preferred approach given the softer social impact. Both scenarios reflect a 3-tiered structure for residential

(Rate A) with a flat structure for all other rate groups. The cross-subsidisation scenario reflects a zero percent increase for the first tier for residential (Rate A) customers for the first year (2004). See table 4(b) page 26.

The aforementioned strategies have given rise to a number of capital projects amounting to over $600M in the first year (2004) which will be financed in the following ways:-

- bonds and other long-term loans, guaranteed by the Government of the Republic of Trinidad and Tobago
- revenue earned from adequate tariffs.
- short-term funds

2 ASSESSMENT OF EXTERNAL ENVIRONMENT

The 2004 to 2008 Business Plan has been influenced by issues related to the economy, customer factors, shareholder's objective, regulatory, health and safety, technological factors and social issues.

2.1 Economic Influences

Three (3) key economic variables, which will continue to impact upon T&TEC's operations in the coming years, are imported inflation, economic growth and cost of borrowing.

2.1.1 Imported Inflation

Crude oil prices, which have hitherto fluctuated between 26USD and 31USD, have now climbed to about 40USD per barrel. This could fuel inflation in international economies. Given the tendencies to import inflation in Trinidad and Tobago, this development is certain to adversely impact T&TEC's operations in terms of the rising costs of material and freight. In addition, increases in the prices of commodities like steel are likely to aggravate this situation.

2.1.2 Economic Growth

The economy of Trinidad and Tobago has continued to experience strong positive growth as measured by Real Gross Domestic Product (GDP). The rate of growth in 2000, 2001 and 2002 was 5.70%, 4.20% and 3.10%[1] respectively. The Review of the Economy for 2003 estimated that GDP would have increased by 6.70%[1] in 2003. T&TEC expects that Real GDP will continue to grow at about 4.50%[2] in the ensuing years. This could even be higher with the coming of the Caribbean Single Market and Economies (CSME) and the Free Trade Area of the Americas (FTAA).

2.1.3 Cost of Borrowing

The basic prime lending rate declined from 16.50% in 2000 to 15.00% in 2001. It then moved to 12.00% in 2002 and was at 9.50% at the end of 2003.[1] At the end of the third quarter of 2004, this rate had reached 8.75%. It is expected to decrease even further as the economy becomes more liquid. However, T&TEC primarily utilises short-term borrowing instruments such as bankers' acceptances, for which interest rates range from 5.00% to 6.00%. In this scenario, the cost of capital to T&TEC for long and short-term borrowings is expected to decrease.

---

[1] Central Bank of Trinidad and Tobago.

[2] GDP Projections 2003-2013, Corporate Support Department, T&TEC.

2.2 Customer Factors

2.2.1 Customer Base

Over 97% of households have access to a supply of electricity. Despite this very high coverage there still exists pockets of customers whose needs are not entirely met. Appendix 1 gives further explanation of worst served customers.

As at December 31st 2003, the active customer base of T&TEC comprised 346,028 customers including 343,315 residential and commercial customers, 2,317 industrial customers and 396 street lighting customers.

It is envisaged that the favourable economic environment mentioned above will give rise to an increase in the customer base as seen by T&TEC's customer forecast in Table 1 below where the number of customers is expected to increase by approximately 6% over the planning period.

Table 1

Year	Base Forecast - Total Number of Customers in each Rate Category							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004	311,845	31,916	1,711	696	31	2	406	346,608
2005	316,571	32,239	1,747	711	32	2	406	351,708
2006	321,377	32,565	1,784	726	33	2	406	356,892
2007	326,262	32,895	1,821	742	33	2	406	362,161
2008	331,230	33,228	1,859	757	33	2	406	367,516

2.2.2 Demand Forecast

An increase in the customer base will certainly translate into demand for electricity as evinced in Table 2 where it is seen that sales of electricity are expected to increase from 6,121 Gigawatt hours (GWh) in 2004 to 6,960 GWh in 2008 or almost 14%.

This will indeed impact on peak demand delivered by the electric system. The most recent peak demand forecast (Table 3) 2004 to 2008, which was done in 2003, shows that by 2008 system peak demand is expected to reach 1,152MW, an increase of more than 200MW over the 2002 peak of 930 MW. In order to match these increases in demand generating capacity will be required. The methodology employed to conduct this forecast is seen in Attachment 1 titled "Energy Sales & Peak Demand

Forecast Methodology." Appendix 2A gives a high forecast for the period under review, while Appendix 2 (B to C) gives base and low. Appendices 3 and 4 give details pertaining to the improvement in demand (load) research and demand (load) monitoring that T&TEC will be undertaking. These measures are expected to yield valuable information that would assist in forecasting, system planning, tariff design and cost allocation.

Table 2

Year	Base Forecast - Total Sales to each Rate Category (GWh)							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004	1,560	578	424	1,090	993	1,457	19	6,121
2005	1,610	594	439	1,129	1,161	1,461	19	6,413
2006	1,683	613	452	1,161	1,205	1,523	19	6,656
2007	1,768	634	463	1,192	1,205	1,523	19	6,804
2008	1,862	655	474	1,218	1,209	1,523	19	6,960

Table 3

Year	Forecast System Peak Demand (MW)
2004	1,013
2005	1,064
2006	1,105
2007	1,129
2008	1,152

2.2.3 Customer Service

Customers will continue demanding a higher level of customer service in terms of the "soft" people/service issues and the "hard" product issues both of which are determined by one or more of the following: quality, reliability, dependability, availability, delivery, and safety.

Customers, to ensure attainment of these objectives, will continue making strong representations to the Government, the regulatory authority - the Regulated Industries Commission (RIC), the Ombudsman and the news media.

T&TEC must continue to respond positively to these issues if its customers are to achieve a higher level of satisfaction. T&TEC, as a result, must continue articulating and implementing policy initiatives and improving methods and procedures for satisfying these customer demands.

2.3 Shareholder's Objective

The Government of the Republic of Trinidad and Tobago (GORTT) is T&TEC's major stakeholder as well as being its sole 'shareholder'. Therefore GORTT's views must be taken into consideration in developing T&TEC's Business Plan.

Central to GORTT's policy is its Vision 2020 – the transformation of Trinidad and Tobago into a developed nation by the year 2020. The Honourable Prime Minister has articulated that Vision 2020 projects a thriving, diversified economy; full employment; an educated, skilled citizenry; modern, accessible health care; upgraded, efficient infrastructure; housing for all; poverty eradication and a safe, secure Trinidad and Tobago. It has been posited that the attainment of developed country status will be measured by three (3) yardsticks – the level of efficiency, the efficacy of social systems and the level of the standard of living.

Provision of electricity and street lighting to the vast majority of citizens of Trinidad and Tobago is a key requirement for the achievement of this Vision. While electricity is already supplied to over 97% of citizens, T&TEC will be required to extend supplies to remote and rural parts of the country which have not benefited from electricity because of cost constraints and inadequate revenue flows. GORTT will be partly funding the projects through its National Social Development Programme (NSDP). In addition, a rural electrification programme will be partly funded by the European Commission (EC). T&TEC will also provide funding for this programme to the tune of $5.0M annually.

Another major policy initiative of GORTT is the development of new industrial estates and the promotion and establishment of large-scale electricity intensive industries based on low cost and competitive electricity pricing.

These initiatives will require significant expansion of generation capacity and the transmission and distribution networks over the next few years and continuing into the future. In addition, GORTT will have to make appropriately priced natural gas available for the provision of low cost electricity to domestic consumers as well as large-scale electricity intensive industries.

2.4 Regulatory Factors

GORTT has changed the regulatory environment under which T&TEC operates through the establishment of a new regulatory body, the Regulated Industries Commission (RIC).

The RIC is vested with wider powers and greater monitoring responsibilities than previously obtained with its predecessor, the Public Utilities Commission (PUC). Under this arrangement customer service and performance targets are being set and penalties will be exacted if targets are not met. To this end, Quality of Service Standards were implemented by the RIC in April 2004. The implementation of these Quality of Service Standards meant that T&TEC was required to put systems and procedures in place to ensure that:

- the relevant data was properly captured and co-ordinated;
- auxiliary forms to facilitate the capture of data were designed and implemented;
- staff were assigned, who would be fully dedicated to this function.

To this end, T&TEC spent approximately $0.5M on its public relations campaign, and continues to incur a monthly cost of approximately $40,000 on staffing and stationery expenses

This new body is introducing new bases for setting tariffs such as “price capping” and will ease the constraint regarding timeliness of rate adjustments through an indexation mechanism. Under this new arrangement the RIC will determine the price limits every five (5) years and T&TEC will have the option of modifying rates within the limits.

2.5 Health, Safety and Environmental Factors (HSE)

T&TEC is required to comply with a number of laws pertaining to health and safety in the work place and to conduct its operations cognisant of its responsibility for ensuring the integrity of the environment.

Health and Safety issues are continually being assessed, reviewed and audited so as to ensure that the organisation is meeting its stated objectives and targets in achieving health, safety and environmental excellence.

2.6 Technological Factors

2.6.1 Advances in Technology

The pace of advances in telecommunications and information technology such as the internet and the intranet has indeed been aggressive in addressing the need for timely, adequate and accurate information worldwide. This in turn can impact positively on the quality of decision-making in organisations. In addition, development in equipment, materials and systems utilised in transmission and distribution networks can assist T&TEC in the delivery of a more reliable and higher quality electricity service.

2.6.2 Renewable Energy

The use of renewable forms of energy generally benefits the environment as they contribute little or nothing to pollution. In addition, the utilisation of these technologies will reduce the demand for natural gas for electrical energy conversion.

The renewable energy industry has made significant technical progress in the last ten (10) years. The cost of these technologies has been falling and it can be expected that there will be further reduction over the next five (5) years.

The supply of electricity to small rural communities may lend itself to this approach as the cost of building long overhead lines to these communities and the maintenance of these lines may prove to be of the same order, if not higher, than the cost of the alternative of utilising an appropriate renewable technology.

2.7 Social Issues

2.7.1 National Social Development Programme (NSDP)

GORTT's commitment to a significant housing thrust as well as funding for the NSDP will ensure new demand in the residential sector for electricity over the next five (5) years.

2.7.2 Crime

In recent years, there has been a steep rise in the rate of crime such as murders, kidnappings, robbery and illegal narcotics. This problem has resulted in grave insecurities among the citizenry in general and the business community in particular. This could have a negative impact on economic growth. Lately, T&TEC workers have also been targeted while on duty. T&TEC is currently addressing this issue.

3 BUSINESS PARAMETERS

The key business parameters within which T&TEC will be expected to operate between 2004 – 2008 have been identified as follows:

- Legal Framework
- Mission
- Vision
- Fixed Assets
- Financial viability
- Generation Capacity
- Transmission and Subtransmission Infrastructure
- Distribution Infrastructure
- Human Resources.

3.1 Legal Framework

T&TEC's operations have been defined by The Trinidad and Tobago Electricity Commission Act Chapter 54:70 as amended by Act No. 32 of 1994 which vests T&TEC with the following powers to:-

a) manage and operate works acquired by the Commission pursuant to the Act;
b) establish, manage and operate such works as the Commission may consider expedient to establish;
c) promote and encourage the use of energy with a view to the economic development of Trinidad and Tobago;
d) advise the Government on all matters relating to the generation, transmission, distribution and use of energy.

3.2 Mission

The Mission statement of T&TEC is as follows:-

> "**Provide the public with a reliable, safe and adequate supply of electricity in the most efficient manner and at prices required by law to meet both the present and future social and economic needs of the Republic of Trinidad and Tobago"**

3.3 Vision

The Vision statement is as follows:-

> **"To become a customer-oriented, highly efficient and reliable provider of quality energy, driven by high performing teams to achieve sustainable growth and value for all."**

3.4 Fixed Assets

As at December 2002 audited financial statements show that T&TEC had total assets of just under $2.4B. This included fixed assets of approximately $1.2B comprising land and buildings, vehicles, generating assets, and transmission and distribution, control and communications and information technology facilities.

As at December 2003, total assets increased to $2.5B, including fixed assets of $1.3B.

3.5 Financial Viability

Audited accounts for 2003 show that T&TEC experienced an operating loss of $26.9M, down from $56.7M in 2002 and from $121.0M in 2001. The main reasons for the continuing decrease in the operating loss were net increases in revenue of $137.0M in 2002 over 2001 and $111.0M in 2003 over 2002; and net increases in expenditure - $73.0M between 2001 and 2002, and $82.0M between 2002 and 2003. The accumulated deficit stood at $645.0M at the end of 2003, down from $955.0M at the end of 2002. This decrease of $310.0M was as a result of a net decrease of $337.0M in T&TEC's liability for retirement benefit obligations, in accordance with International Accounting Standard (IAS) 19 – Employee Benefits. (See Appendices 5, A to C and 6, A to D). This decrease in operating loss is not expected to continue as a deficit of $75.0M is budgeted for 2004.

Expenditures are generally more than revenues from the sale of electricity but the resulting deficit is reduced by the receipt of dividends from The Power Generation Company of Trinidad and Tobago Limited (PowerGen) and other miscellaneous revenue. At least four (4) reasons can be advanced for this situation:

- Uneconomic Tariff Structures
- Escalating Fuel and Bulk Power Purchase Costs
- Financial Constraints
- High Levels of Receivables

3.5.1 Uneconomic Tariff Structures

The 2001 "Cost of Service Study" Appendix 7A shows that the prices paid by Rates A, B and Street Lighting customers, which comprise 35% of all revenue, do not cover the cost of providing service to these groups.

In addition, the overall loss for all customers is 4.4cents per kWh. This position is expected to deteriorate over the forecast period 2004 to 2008. Details of this study can be seen in Appendix 7 (B to F). T&TEC will therefore set economic rates within the price limits determined by the RIC and consistent with its policy of Demand-Side Management, which in the first instance would seek to limit growth in system demand, while promoting overall sales growth in system peak demand. T&TEC recognizes the need to further explore Demand-Side Management, which will be done at a later date. A position paper on Demand-Side Management entitled "Demand-Side Management: Application to T&TEC's Reality" is seen in Attachment 2. The introduction of the use of compact fluorescent bulbs to Rate A customers, to soften the impact of increases that may result from the rate review, is being considered under Demand-Side Management.

3.5.2 Escalating Fuel and Bulk Power Purchase Costs

T&TEC's cost structure is such that 70% is attributable to the purchase of natural gas from the National Gas Company and conversion costs payable to the two generating companies. Conversion costs, which are determined by Power Purchase Agreements (PPA) with suppliers, escalate at about 2.5% per annum. Natural gas prices, based on a Cabinet decision of 1995 have escalated annually at 4%. T&TEC has little day-to-day control over these costs and there is, at present, no long-term contract with NGC.

T&TEC's fuel and bulk power purchase costs are quoted in $US and as such any adverse change in exchange rates results in increased costs to T&TEC, some of which are recovered. Appendix 8 (A to B) shows forecast of fuel price, cost and energy purchases.

3.5.3 Financial Constraints

T&TEC's ability to obtain long-term funding is constrained by the provisions of the T&TEC Act, the Exchequer and Audit Act and the Statutory Authorities Act, which require T&TEC to obtain certain approvals for any loan with a repayment period of over one year. The process of obtaining these approvals has been very time consuming and tedious.

Given the highly capital intensive nature of the electricity business, this inability to expeditiously source long-term capital funding has forced T&TEC to inefficiently finance long-term investments with operating revenues and short-term debt.

Given the constraints that exist with respect to long-term funding, T&TEC will continue to operate in this mode unless its tariffs are adjusted such that they cover operating expenses, meet repayments of long-term debt and create reserves for future expansion.

3.5.4 High Levels of Receivables

The current high levels of receivables continue to severely affect T&TEC's ongoing operations, development plans and cash flow position. This situation is more critical in the Public Sector where indebtedness is unacceptably high at 111 days, as at June 2004.

As a result, T&TEC is finding it extremely difficult to meet its obligation to National Gas Company (NGC) on a timely basis.

3.6 Generation Capacity

T&TEC is viewed as a Transmission and Distribution company having responsibility for generation in Tobago only. However, T&TEC is still fully responsible for generation planning and ensuring that the required generation reliability is maintained. In this regard, the planning decisions of where, when, type and quantity – as they relate to capacity planning remain with T&TEC.

T&TEC hopes to provide for the additional demand in the short-term by utilising the extra capacity available from the existing power generators and to institute a demand side management programme. At the same time, the process for sourcing new generation both in Trinidad and Tobago has started.

3.7 Transmission and Subtransmission Infrastructure

The Transmission and Subtransmission Systems need to be very reliable as a failure can result in widespread outages. T&TEC continually examines these systems and effects reinforcement when required to ensure that bulk power is delivered reliably from the power stations to the load centres.

Although no major Transmission upgrade has been done since 1984, T&TEC has already developed its Transmission and Subtransmission plans for the next 20 years. Significant works are targeted, over the next three (3) years, for the northern part of the System and in particular, the Port of Spain area with the introduction of 132kV in the city. This will position the Transmission System to deal with whatever long-term strategy is determined for the ageing generating units at the Port of Spain Power Station.

Transmission development in the South is to a large extent linked to GORTT's initiative in developing a new industrial estate in the La Brea area and, in particular, the establishment of a proposed Aluminum Smelter Complex.

The development work in Tobago will be associated with interconnecting the proposed new Power Station to the grid.

3.8 Distribution Infrastructure

The Distribution System forms the largest portion of T&TEC's electric infrastructure, virtually covering the entire country. This part of the System connects directly to approximately T&TEC's 346,000 customers. Operating this System is very challenging and T&TEC is continually looking for new and more cost effective systems and methods to improve the reliability and quality of supply it delivers to its customers.

3.9 Human Resources

3.9.1 Organisational Structure

T&TEC is structured into five (5) functional Divisions – Transmission and Distribution, Engineering, Finance, Human Resources and Administration. An Assistant General Manager who reports directly to the General Manager heads each Division.

The General Manager is responsible and accountable for managing all T&TEC's operations to ensure that customers are provided with a reliable supply of electrical energy in a cost-effective manner. He reports to a Board of Commissioners appointed by the President of the Republic of Trinidad and Tobago.

Details of T&TEC's Organisational Structure are outlined in Appendix 9.

3.9.2 Establishment

The total number of individuals employed by T&TEC was 2,316 as at December 2003. Of this amount, 1,937 were permanent and 379 were temporary employees. This equates to a ratio of employees to customers of 1 to 149.

3.9.3 Human Resource Development and Training

Strategies are devised to ensure the development of T&TEC's human resources in effective management, supervisory skills and techniques, in addition to technical and engineering training. With regard to technical training, T&TEC has strengthened its alliances with the University of the West Indies and other institutions in order to enhance the organisation's capabilities in the area of its core business competency.

4 RISK AND UNCERTAINTIES

It is highly unlikely that any of the external environmental factors discussed above will threaten T&TEC's operations. All lie in the area of opportunities rather than threats. However, a few business parameters will pose threats to T&TEC as follows:

4.1 Uneconomic Tariff Structures

In order to manage this threat T&TEC needs to continue its efforts to seek rates that cover its cost of service for all categories of customers and generate a fair rate of return.

4.2 Escalating Power Conversion Costs

To manage this threat T&TEC, in sourcing additional capacity must seek more favourable terms and conditions for power conversion in order to minimize its costs.

4.3 Collection of receivables

In general, T&TEC's current practice for dealing with customers in default of payment and write-off of bad debt can be seen in <u>Appendix 10 (A to B)</u>.

4.4 Competition from National Gas Company (NGC)

T&TEC is faced with growing competition from the National Gas Company as it pursues its policy of promoting natural gas as a substitute for electricity.

4.5 Customer Base

T&TEC's customer base is highly skewed in that there were approximately 343,000 residential and commercial customers and some 2,300 industrial customers as at December 31st, 2003. The latter category includes a few very large multinational companies, which account for a significant proportion of T&TEC's revenue. This aspect of T&TEC's revenue base is therefore a potential risk should any of these companies elect to move its operations out of this country.

5 KEY BUSINESS ISSUES

In order to respond to the environmental factors discussed above and to function within the stated business parameters, T&TEC has identified the following five (5) key business issues:

- Continue to enhance the level of customer service
- Achieve a balance in the supply/demand relationship
- Maintain the network infrastructure and assets
- Continue to realize efficiency improvements
- Seek to obtain tariffs which would satisfy revenue requirements

Strategies for the realization of each key business issue follow.

5.1 Strategies for the enhancement of the level of customer service

T&TEC will continue to enhance the level of customer service by instituting the following systems:

- A Customer Call Centre
- Automatic Meter Reading System

5.1.1 Customer Call Centre

Trouble Call Management is the process of both managing the inbound avalanche of calls that follows a power outage, and managing the outbound provisions of that same information to field crews, customers, stakeholders and others as required.

The issues involved with Trouble Call Management are:

- Outages are unexpected and unplanned, generally having the most impact after normal office hours when customers are at home, and there is limited staff available to handle the large volume of customers calls.
- Most customers want answers to the same questions: Does the utility know the power is out? What caused the outage? And when will power be restored?

- Phone lines become swamped, resulting in many customers receiving busy signals.
- System and time constraints limit the ability to provide outage information to other areas of the business.
- Outage messages produced by staff in these high-pressure situations must be professional and informative.
- The time it takes to handle hundreds of calls from concerned customers, some with key outage information, means staff cannot relay information adequately to aid restoration and efficient information flow.
- The Corporate Communications Department must be notified of any major incident so that external communication issues can be addressed.
- Without key outage information from customers, vital time is lost in determining what the specific cause of the problem is.

T&TEC proposes to resolve these issues with the aid of a centralised customer call centre. Its implementation is expected to greatly improve the service given to our customers.

5.1.2 Automatic Meter Reading

Accessing meters has been an on-going problem faced by T&TEC. The resulting estimated billing, continues to have a negative impact on customer service. A number of initiatives e.g. reading meters outside normal working hours, has resulted in significant reduction in unscheduled estimated billing. However, to improve efficiency and customer service, available technological options were reviewed and a pilot project using automatic meter reading was undertaken.

Benefits from the implementation of Automatic Meter Reading (AMR) are:

- Improved accuracy in reading meters
- Enhancement of the revenue collection programmes due to accurate billing of consumption on a timely basis.
- Improvement in the ability to detect meter tampering and energy theft.
- Improved cash flow and freed resources for utilisation in other productive area resulting from a reduction in estimated bills, billing complaints and queries.

T&TEC plans to extend the AMR project to all its customers.

5.2 Strategies for the achievement of supply/demand balance

5.2.1 Generation and Transmission

Maintaining the balance between supply and demand is achieved by appropriate planning of the power system at the generation, transmission and distribution levels. This planning must take place well in advance of the date at which supply is needed, to cater for the lead times which may be as long as three years for generation and transmission projects and eighteen months for distribution projects.

The need to determine system requirement well in advance of the in-service date consequently imposes the additional need for forecasts of demand over the planning period. The planning horizon is determined based on the objectives of the study and the useful life of the plant to be installed.

In long-term planning studies, T&TEC uses a 20-year planning horizon.

For generation studies, a global forecast of net units generated and purchased is obtained from T&TEC's annual 10-year *Energy Sales and Peak Demand Forecast*, which is extended as required to cover the planning period. Forecasts for transmission studies consist of projections of individual substation demands, which are based on trending of actual load measurements.

For both generation and transmission studies, T&TEC's standard planning criteria are used to assess system performance and to identify deficiencies.

At the end of this process several alternative schedules of system reinforcement or expansion would have been prepared, identifying specific works to be carried out in certain time frames. The costs and benefits of each alternative are evaluated after which they are ranked in order of decreasing net benefit. Finally, subjective issues are considered and the final recommendation made. By this means therefore, the balance between supply and demand is maintained.

With particular reference to maintaining the supply balance in generation the following is noted: at present, 819MW of capacity is contracted from PowerGen and 195MW @ 90% availability is contracted from Trinity Power Limited (Trinity Power), previously InnCOGEN, for a total of 1,014MW. In 2003, the system peak demand was 970MW and is projected to rise to 1,152MW in 2008. After providing 100MW for spinning reserve, it appears that T&TEC will require at least an additional 250MW to meet the 2008 peak demand. It is expected that this value will increase in subsequent years. Further details of this analysis can be seen in Appendix 11. Projected capital costs for Generation and Transmission for the period 2004-2008 are approximately $450.0M.

5.2.2 Distribution

At the distribution level, the supply/demand balance for electricity service offered to our customers entails monitoring of the existing system, planning and design of infrastructure upgrades/expansions and a structured maintenance program. Further details on the supply/demand balance at the generation, transmission and distribution levels can be seen in Appendix 12 (A to B). Projected capital expenditure for Distribution, for the period 2004-2008 is over $900.0M.

5.3 Strategies for the maintenance of the network and assets

T&TEC has instituted the following measures to improve the effectiveness of its maintenance function:

- The introduction of a manual maintenance work order system as the first stage in the implementation of an integrated Maintenance Management System.
- The adoption of the philosophy of Reliability Centred Maintenance.

5.3.1 The Maintenance Work Order System

The Maintenance Work Order System has achieved the following objectives:

- The quantification and control of maintenance work at each of its distribution areas.
- A more disciplined approach to maintenance since an essential requirement is that work cannot be undertaken without the proper authorisation.

- Formalisation of the maintenance planning process by requiring planning personnel to examine each job closely in order to fit them into a daily schedule of work to be completed.
- A greater awareness of the importance of the maintenance function by requiring the Operations and Maintenance Departments to meet on a weekly basis as part the planning process.
- A greater sense of responsibility among maintenance staff by requiring each person to be accountable for their performance.
- An efficient method for management review of maintenance work.
- The establishment of a basis for a computerised Maintenance Management System.

5.3.2 Reliability Centred Maintenance

Reliability Centred Maintenance (RCM) is the process used to determine the maintenance requirements of any physical asset in its operating context. Further discussion of this topic is dealt with in Appendix 13.

5.4 Strategies for the realization of efficiency improvements

5.4.1 Efficiency Improvements in the last five (5) years

In the last five (5) years T&TEC undertook the following key projects and programmes in order to improve its efficiency.

- Power Factor Correction (Capacitor Placement Project)
- Vehicle Fleet Upgrade
- Pole Replacement
- Establishing of Service Centres
- Restructuring of Transmission & Distribution Division
- Optimizing of Crews
- Shift System for Small Crews and Cable Crews
- Meter Sealing
- Automatic Meter Reading (AMR)
- Risk Management
- Upgrading of the Financial Systems
- Human Resource Training

Detailed discussion of these projects can be seen in Appendix 14.

5.4.2 Plans to improve operating efficiency

In order to improve operating efficiency key strategic business projects have been identified for implementation. These projects fall within the following business areas:

- Transmission and Distribution
- Control and Communications
- Protection and Meter
- Information Technology

Detailed discussion of some of the key projects outlined hereunder takes place in Appendix 15 while an extensive financial presentation is seen in Appendix 16 (A to F).

PROJECT	COST 2004-2008
	$M
New and upgraded substations and transmission lines	573
National Fibre Optic Development	16
Distribution Automation	34
Underground Residential/Commercial Distribution	64
Remote Data Acquisition (AMR)	111
Microwave Radio Replacement	31
Pole Replacement Programmes	80
National Social Development Programme (NSDP)	23

Associated projected operating expenditure and projected income statements are given in Appendices 17 and 18 (A to C) respectively.

Appendix 19 summarises capital expenditure projections, operating and expenditure projections.

Projected key performance indicators are seen in Appendix 20.

5.5 *Strategies for the attainment of economic tariffs*

5.5.1 Price Limits

T&TEC has over the years committed millions of dollars to improving the quality and reliability of electric service to its customers. Unfortunately, this improvement in service has resulted in increased expenditure, which has not been matched by a corresponding increase in tariff.

Since the establishment of the now defunct Public Utilities Commission in 1966, T&TEC has been the recipient of five (5) rate awards, the most recent being in 1997 and applied only to eighteen (18) customers falling under Rates D3 and E. These occurred as follows:-

Claim	Order No.	Effective Date	Return on Rate Base % Proposed	Return on Rate Base % Awarded
Formal Case No. 2	10 (Interim) 13	1968 03 01 1969 05 01	Not Stated -do-	10 10
No. 2 of 1983	42	1984 01 01	10	7.5
No. 1 of 1989 (based on COS 1987)	80 81	1992 10 01 1993 04 22	7.5 Not Applicable	6.5 ERA Clause Defined
No. 1 of 1997	85	1997 01 11	3.85	(5.77)

T&TEC recently reviewed its cost structure by conducting a Cost of Service Study based on its 2001 audited Financial Statements. This, together with the projected COS for 2004 to 2008 including Summary of Bases of Allocation, are shown in Appendix 7 (A to G). This study applied the Average and Excess Demand method for the allocation of demand related costs. This method is widely used by utilities and is considered to be the fairest method of allocating these costs. The application of this concept and the methods used for allocating other costs are outlined in Attachment 3.

The 2001 COS reflected losses for rate groups A, B and Street Lighting and an overall loss for all rate groups combined of 4.4 cents/kWh. New rates are proposed for all rate groups consistent with the Revenue Cap approach. Also, a new charge, namely the Purchased Power Adjustment Charge (PPAC), has been introduced to recover the cost changes resulting from the movement in US CPI and exchange rate as per independent power producers. A brief explanation of the PPAC is outlined in Appendix 21.

Given the aforementioned and the need to achieve the revenue requirement for each group, in compliance with the Revenue Cap concept, rates have been adjusted as seen in the Price Limits schedule (Table 4). The effect of the rate increase in the Income Statement 2004-2008, is shown in Table 5. Two (2) scenarios of Price Limits and Income Statements are presented to reflect:-

a) True or full cost of providing service to each class of consumer
b) Assuming cross-subsidisation within and between rate groups.

The proposed rates are reflected in the sample billings in Appendix 22.

The character of service rules can be seen in Appendix 23.

Appendix 24A, OLADE's Report and Appendix 24B, Carilec Tariff Survey, show a comparison of electricity prices throughout the region.

Table 4 (a)

	Customers 2003	Existing Rates	2004 $/kWh/KVA	2005 $/kWh/KVA	2006 $/kWh/KVA	2007 $/kWh/KVA	2008 $/kWh/KVA
			PRICE LIMITS 2004 - 2008 ASSUMING TRUE/FULL COST				
			BASE CHARGE				
RATE A							
1 - 500kWh	132,767	0.1500	0.3514	0.3746	0.3876	0.3914	0.3964
501 - 1,500kWh	146,717	0.1500	0.3514	0.3746	0.3876	0.3914	0.3964
>1,500kWh	31,258	0.1500	0.3514	0.3746	0.3876	0.3914	0.3964
RATE B	32,573	0.1650	0.3086	0.3225	0.3359	0.3396	0.3463
RATE B 1	0	0	0.4019	0.4219	0.4368	0.4340	0.4421
RATE D1	1,622	0.1675	0.1067	0.1110	0.1176	0.1149	0.1177
		$21.75	$68.74	$70.84	$73.70	$77.69	$79.20
RATE D2	667	0.1520	0.1111	0.1159	0.1224	0.1194	0.1220
		$21.75	$64.50	$66.74	$69.61	$73.23	$74.80
RATE D3	26	0.0690	0.1069	0.1107	0.1168	0.1151	0.1177
		$26.08	$70.28	$75.33	$78.16	$83.22	$85.09
RATE D4	0	0	$0.0813	$0.0826	$0.0873	$0.0819	$0.0849
			$47.36	$51.06	$52.64	$53.95	$55.04
RATE D 5	0	0	$0.0808	$0.0834	$0.0882	$0.0827	$0.0854
		$26.08	$31.65	$33.71	$33.28	$33.62	$34.77
RATE E 1	1	0.0614	$0.0809	$0.0830	$0.0874	$0.0819	$0.0847
		$23.60	$49.68	$52.56	$54.39	$56.16	$57.82
RATE E 5	1	0.0614	0.0814	0.0836	0.0877	0.0821	0.0850
		$23.60	$45.27	$47.72	$50.32	$51.32	$52.79
Street Lighting	396	$1.05	$1.39	$1.47	$1.51	$1.55	$1.59
			OTHER CHARGES				
		$	$	$	$	$	$
Bi-monthly Customer Charge Rate A		4.00	42.15	41.29	41.15	41.02	40.91
Bi-monthly Customer Charge Rate B		20.00	49.07	48.41	48.42	48.44	48.68
Bi-monthly Customer Charge Rate B 1		N/A	36.91	35.68	35.04	34.52	39.40
Fuel Charge		0.0449	*0.0000	*0.0000	*0.0000	*0.0000	*0.0000
ERA Charge		0.0247	*0.0000	*0.0000	*0.0000	*0.0000	*0.0000
PPA/kWh			*0.0000	*0.0000	*0.0000	*0.0000	*0.0000

Note 1) See Appendix 23 for a description and character of service for all rates.
2) * The Fuel, ERA and PPA charges have been included in the base charge of each year. See Appendix 21, A-E for the PPA and Fuel Charges for 2004-2008
3) It is assumed the exchange rate remains fixed at $6.30TT for the 5-year period 2004-2008.

Table 4(b)

PRICE LIMITS 2004 - 2008
ASSUMING CROSS SUBSIDISATION

	Customers 2003	Existing Rates	2004 $/kWh/KVA	2005 $/kWh/KVA	2006 $/kWh/KVA	2007 $/kWh/KVA	2008 $/kWh/KVA
			BASE CHARGE				
RATE A							
1 - 500kWh	132,767	0.2196	0.2145	0.2170	0.2220	0.2270	0.2320
501 - 1,500kWh	146,717	0.2196	0.3100	0.3125	0.3175	0.3225	0.3275
>1,500kWh	31,258	0.2196	0.4450	0.4475	0.4500	0.4525	0.4550
RATE B	32,573	0.2346	0.3135	0.3160	0.3210	0.3260	0.3310
RATE B 1	N/A	N/A	0.4140	0.4190	0.4240	0.4290	0.4340
RATE D1	1,622	0.2371	0.1910	0.1960	0.2010	0.2060	0.2110
		$21.75	$62.00	$62.25	$62.50	$62.75	$63.00
RATE D2	667	0.2216	0.1815	0.1840	0.1865	0.1890	0.1915
		$21.75	$60.50	$60.75	$61.00	$61.25	$61.50
RATE D3	26	0.1386	0.1140	0.1165	0.1190	0.1215	0.1240
		$26.08	$54.00	$54.25	$54.50	$54.75	$55.00
RATE D4	N/A	N/A	$0.1140	$0.1165	$0.1190	$0.1215	$0.1240
			$52.00	$52.25	$52.50	$52.75	$53.00
RATE D 5	N/A	N/A	$0.1590	$0.1615	$0.1640	$0.1665	$0.1690
			$30.00	$30.25	$30.50	$30.75	$31.00
RATE E 1	1	0.1310	$0.1050	$0.1075	$0.1100	$0.1125	$0.1150
		$23.60	$51.00	$51.50	$52.00	$52.50	$53.00
RATE E 5	1	0.1310	0.0920	0.0945	0.0970	0.0995	0.1020
		$23.60	$46.00	$46.50	$47.00	$47.50	$48.00
Street Lighting	396	$1.05	$1.48	$1.52	$1.57	$1.62	$1.67
			OTHER CHARGES				
		$	**$**	**$**	**$**	**$**	**$**
Bi-monthly Customer Charge Rate A		4.00	4.00	5.00	6.00	8.00	10.00
Bi-monthly Customer Charge Rate B		20.00	40.00	42.00	44.00	46.00	48.00
Bi-monthly Customer Charge Rate B 1		N/A	0.00	0.00	0.00	0.00	0.00
Fuel Charge		0.0000	0.0000	0.003419	0.010595	0.009486	0.013152
ERA Charge		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
PPA/kWh		0.0000	0.0052	0.0076	0.0112	0.0160	0.0187

Note 1) See Appendix 23 for a description and character of service for all rates.
2) The Fuel and ERA charges have been included in the base charge in 2004.
This amounts to $0.0449/kWh, $0.0247/kWh and $0.0054/kWh, respectively.
See Appendix 21, A-E for the PPA and Fuel Charges for 2004-2008
3) It is assumed the exchange rate remains fixed at $6.30TT for the 5-year period 2004-2008.

Table 5(a)

INCOME STATEMENT
FORECAST 2004-2008 WITH TRUE COST AND RATE INCREASE

Description	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Sales - kWh	6,121,000,000	6,413,000,000	6,656,000,000	6,804,000,000	6,960,000,000
Average Revenue per kWh -cts	28.07	29.16	30.18	30.49	31.95
INCOME	$	$	$	$	$
Sales of Electricity	1,718,248,398	1,870,253,171	2,008,764,933	2,074,857,349	2,173,749,131
Other Income	149,239,118	151,655,885	153,012,445	154,369,003	155,752,693
TOTAL INCOME	1,867,487,516	2,021,909,056	2,161,777,378	2,229,226,352	2,329,501,824
EXPENDITURE					
Generation	1,227,959,492	1,334,322,917	1,453,841,214	1,501,708,140	1,580,878,052
Transmission	12,298,338	12,818,889	13,181,164	13,403,749	13,788,707
Distribution	214,117,056	211,033,657	213,018,107	214,844,417	216,876,603
Administration & General	124,195,243	129,037,521	130,100,838	130,261,910	131,401,529
Depreciation	80,411,289	82,201,905	84,202,635	86,764,661	89,332,308
Interest	88,954,923	107,000,000	107,000,000	107,000,000	107,000,000
TOTAL EXPENDITURE	1,747,936,341	1,876,414,888	2,001,343,957	2,053,982,878	2,139,277,199
NET SURPLUS/(DEFICIT)	119,551,175	145,494,168	160,433,421	175,243,474	190,224,625
Rate Base	1,594,015,721	1,939,922,212	2,139,112,234	2,336,579,630	2,536,328,354
Return on Rate Base - %	7.50	7.50	7.50	7.50	7.50

Table 5(b)

INCOME STATEMENT
FORECAST 2004-2008 WITH CROSS SUBSIDISATION AND RATE INCREASE

Description	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Sales - kWh	6,121,000,000	6,413,000,000	6,656,000,000	6,804,000,000	6,960,000,000
Average Revenue per kWh -cts	28.03	28.87	30.27	30.57	33.24
INCOME	**$**	**$**	**$**	**$**	**$**
Sales of Electricity	1,715,525,554	1,851,311,927	2,015,030,470	2,127,325,040	2,261,951,211
Other Income	149,239,118	151,655,885	153,012,445	154,369,003	155,752,693
TOTAL INCOME	1,864,764,672	2,002,967,812	2,168,042,914	2,281,694,043	2,417,703,905
EXPENDITURE					
Generation	1,227,959,492	1,334,322,917	1,453,841,214	1,501,708,140	1,580,878,052
Transmission	4,217,639	4,810,930	4,939,345	4,973,397	5,108,113
Distribution	204,959,037	201,719,739	203,522,690	205,163,523	207,005,158
Engineering Administration	12,949,359	12,903,837	13,186,656	13,424,147	13,724,328
Administration & General	128,484,602	133,455,560	134,651,419	134,949,009	136,229,241
Depreciation	80,411,289	82,201,905	84,202,635	86,764,661	89,332,308
Interest	88,954,923	107,000,000	107,000,000	107,000,000	107,000,000
TOTAL EXPENDITURE	1,747,936,341	1,876,414,888	2,001,343,957	2,053,982,878	2,139,277,199
NET SURPLUS/(DEFICIT)	116,828,331	126,552,924	166,698,957	227,711,165	278,426,705
Rate Base	1,594,015,721	1,939,922,212	2,139,112,234	2,336,579,630	2,536,328,354
Return on Rate Base - %	7.33	6.52	7.79	9.75	10.98

6 PROJECT FINANCING

Section 23 (2) of the T&TEC Act provides inter alia for T&TEC to apply some of its revenue to 'the creation of reserve funds to finance future expansion'. Over the years the revenue earned has been insufficient to meet operating expenses, so that T&TEC has been unable to create these 'reserve funds'.

T&TEC has, in the past, utilised the following sources to finance its strategic objectives:

- short-term funds to meet long-term liabilities
- bonds and other long-term loans, guaranteed by the Government of the Republic of Trinidad and Tobago
- delay in making payments to one of its largest suppliers.

In recognition of its mission to provide the public with a reliable, safe and adequate supply of electricity, and the role it is required to play in the future development of the country, T&TEC has proposed strategic objectives for both capital and recurrent expenditure that will require annual funds totaling over $2.0B. See Appendix 19. In order to finance the capital works required to meet these objectives, T&TEC requires a rate increase that will adequately cover both operating costs and capital expenditure.

Based on cashflow projections for the period, the funds required to meet capital and recurrent expenditure will be sourced from a combination of:

- additional funds arising from adequate tariffs;
- new long-term loans, assuming a moratorium of three (3) years, with repayments starting in 2008;
- short-term loans, using secured overdraft facilities

In the absence of a review of its rates, T&TEC will have to continue to utilise the sources of funding as obtained in the past. This in turn will lead to the continued deterioration in T&TEC's financial viability and ultimately the service it is able to provide to its customers.

7 CONCLUSION

The most critical issue confronting T&TEC is the uneconomic rates at which it sells its electricity services to customers in the Residential (Rate A), Commercial (Rate B) and Street Lighting categories. This issue strikes at the heart of T&TEC's inability to achieve desired levels of profitability and ultimately, viability. T&TEC must be able to:

- continue to meet the growing demands for electricity;
- continue to deliver a quality supply of electricity and service to its customers
- develop its infrastructure;
- do its part to ensure that the GORTT's Vision 2020 is realised;

It is therefore essential that T&TEC be allowed rates that cover its cost of operations and generate a fair rate of return if it is to survive and prosper in the ensuing years in a properly funded electric utility sector. T&TEC, therefore, calls on the RIC to address this situation urgently.

8 APPENDICES

APPENDIX	DESCRIPTION
1	Report on Worst Served Customers
2 A	Optimistic Forecast for Review Period 2004-2008
B	Base Forecast for Review Period 2004-2008
C	Conservative Forecast for Review Period 2004-2008
3	Load Research Programme
4	SubStation Load Monitoring
5 A	Balance Sheet 2001
B	Revenue & Expenditure Account 2001
C	Fixed Asset Statement 2001
6 A	Balance Sheet 2003
B	Revenue & Expenditure Account 2003
C	Analysis of Income 2003
D	Analysis of Expenditure 2003
7 A	Cost of Service Study 2001
B	Cost of Service Study 2004
C	Cost of Service Study 2005
D	Cost of Service Study 2006
E	Cost of Service Study 2007
F	Cost of Service Study 2008
G	Summary of Bases of Allocation
8 A	Forecast of Annual Fuel Price & Fuel Cost
B	Forecast of Energy Purchases from Power Suppliers
9	Organisational Structure
10 A	Collection of Bad Debts
B	Procedure for the Write-off of Bad Debts
11	Contract Capacity Increases 2004-2008
12 A	Maintaining the Supply/Demand Bal at the Generation & Transmission Level
B	Maintaining the Supply/Demand Balance at the Distribution Level
13	Reliability Centred Maintenance
14	Efficiency Improvements
15	Plans to Improve Operating Efficiency 2004-2008
16 A	Projected Capital Expenditure – Transmission
B	Projected Capital Expenditure – Distribution
C	Projected Capital Expenditure – Protection & Meter
D	Projected Capital Expenditure – Information Systems
E	Projected Capital Expenditure – Commercial
F	Projected Capital Expenditure –Control & Communications
G	Projected Captial Expenditure – Administration & Generation
17	Analysis of Expenditure 2004-2008
18 A	Income Statement 2004-2008
B	Income Statement by Resource Category 2004-2008
C	Income Statement by Activity 2004-2008
D	Balance Sheet Forecast 2004-2008
19	Summary of Capital and Operating Expenditure
20	Performance Indicators
21A	Purchased Power Adjustment Clause
B	Fuel Charge 2005
C	Fuel Charge 2006
D	Fuel Charge 2007
E	Fuel Charge 2008
22	Billing Scenarios
23	Character of Service
24 A	OLADE's Report
B	Carilec Tariff Survey
Attachment 1	Energy Sales & Peak Demand Forecast Methodology
Attachment 2	Demand Side Management
Attachment 3	Average & Excess Methodology

TRINIDAD AND TOBAGO ELECTRICITY COMMISSION

T&TEC

BUSINESS PLAN 2004- 2008

CONTENTS

APPENDIX 1

APPENDIX 1

REPORT ON WORST SERVED CUSTOMERS

The Distribution system serves approximately 346,000 customers in Trinidad and Tobago. The Generation Transmission and Distribution systems have enough capacity to supply the present needs of these customers so that there is no need for load shedding of customers during peak hours.

Our worst served customers can be categorized into two groups:

1. Those receiving a relatively unreliable supply of electricity
2. Those with response times for request for service significantly larger than our average response

Average Response Time

The average response time to trouble calls for 2003 was 2.3 hours. The following areas have average response times in excess of 5 hours over the last 3 years and can be considered our worst served areas as far as response to customers' trouble calls. These areas can be defined as being far from our operating centers and the excessive response is due to the travel time needed to reach these locations.

Areas:-

- Grand Riviere
- Balandra
- Brasso Seco Matelot

Reliability of Supply

Areas affected by reliability issues are Saunders Trace, Erin, Cedros to Icacos in the South and Matelot in the East. These areas are supplied by radial feeds and as such there are no provisions for isolating defective plant and restoring supply from another source.

Projects to Improve the Quality of Service

- Increase Hotline Maintenance
- Automation of the Distribution System
- Construction of new substations and the addition of new transformers
- Establishment of a Customer Call Centre
- Implementation of a computerized work management system

APPENDIX 2A

OPTIMISTIC FORECAST FOR THE REVIEW PERIOD 2004 to 2008

Tables 1 to 4 below contain the Optimistic Energy Sales and Peak Demand Forecast developed specifically for T&TEC's submissions in support of its 2003 rate application.

Table 1

Year	Optimistic Forecast - Total Sales to each Rate Category (GWh)							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004	1,576	584	428	1,101	1,135	1,529	19	6,372
2005	1,626	600	443	1,140	1,302	1,532	19	6,663
2006	1,700	619	457	1,173	1,352	1,597	19	6,916
2007	1,786	640	468	1,204	1,397	1,645	19	7,159
2008	1,881	662	479	1,230	1,402	1,808	19	7,480

Table 2

Year	Optimistic Forecast - Total Total of Monthly Demands of each Rate Category (MVA)							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004			1,458	3,177	2,485	3,241		10,361
2005			1,514	3,297	2,819	3,241		10,871
2006			1,561	3,374	2,915	3,283		11,132
2007			1,597	3,455	2,961	4,499		12,511
2008			1,637	3,506	2,961	4,795		12,898

Table 3

Year	Optimistic Forecast - Total Total Units Sent Out (USO) to each Area (GWh)						Losses	
	North	South	East	Central	Tobago	Total	% USO	% Sales
2004	1,486	1,304	1,195	2,749	186	6,920	7.9	8.6
2005	1,555	1,343	1,263	2,872	196	7,229	7.8	8.5
2006	1,627	1,395	1,286	2,988	208	7,504	7.8	8.5
2007	1,698	1,519	1,297	3,035	219	7,768	7.9	8.5
2008	1,769	1,735	1,308	3,069	232	8,113	7.8	8.4

Table 4

Year	Optimistic Forecast - Total Coincident Demand in each Area (MW)					System Demand (MW)	Load Factor
	North	South	East	Central	Tobago	Total	(%)
2004	210	187	168	455	33	1,053	74.8
2005	220	193	178	475	35	1,103	74.8
2006	231	201	182	496	37	1,146	74.8
2007	241	219	183	503	39	1,185	74.8
2008	250	249	184	508	42	1,232	74.9

APPENDIX 2B

BASE FORECAST FOR THE REVIEW PERIOD 2004 to 2008

Tables 1 to 5 below contain the Base Energy Sales and Peak Demand Forecast.

Table 1

Year	Base Forecast - Total Number of Customers in each Rate Category							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004	311,845	31,916	1,711	696	31	2	406	346,608
2005	316,571	32,239	1,747	711	32	2	406	351,708
2006	321,377	32,565	1,784	726	33	2	406	356,892
2007	326,262	32,895	1,821	742	33	2	406	362,161
2008	331,230	33,228	1,859	757	33	2	406	367,516

Table 2

Year	Base Forecast – Total Sales to each Rate Category (GWh)							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004	1,560	578	424	1,090	993	1,457	19	6,121
2005	1,610	594	439	1,129	1,161	1,461	19	6,413
2006	1,683	613	452	1,161	1,205	1,523	19	6,656
2007	1,768	634	463	1,192	1,205	1,523	19	6,804
2008	1,862	655	474	1,218	1,209	1,523	19	6,960

Table 3

Year	Base Forecast - Total Total of Monthly Demands of each Rate Category (MVA)							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004			1,449	3,148	2,485	3,241		10,323
2005			1,501	3,255	2,819	3,241		10,816
2006			1,544	3,341	2,901	3,283		11,068
2007			1,583	3,423	2,901	3,283		11,189
2008			1,620	3,474	2,901	3,283		11,277

Table 4

Year	Base Forecast - Total Units Sent Out (USO) to each Area (GWh)						Losses	
	North	South	East	Central	Tobago	Total	% USO	% Sales
2004	1,472	1,242	1,181	2,584	184	6,663	8.1	8.8
2005	1,540	1,281	1,248	2,708	193	6,970	8.0	8.7
2006	1,611	1,327	1,273	2,823	206	7,240	8.0	8.7
2007	1,679	1,376	1,284	2,852	218	7,409	8.2	8.9
2008	1,751	1,429	1,295	2,882	230	7,587	8.3	9.0

Table 5

Year	Base Forecast - Coincident Demand in each Area (MW)					System Demand	Load Factor
	North	South	East	Central	Tobago	(MW)	(%)
2004	208	178	166	427	33	1,013	74.9
2005	218	184	176	449	35	1,062	74.9
2006	228	191	180	468	37	1,104	74.8
2007	238	198	181	473	39	1,129	74.9
2008	248	205	182	477	41	1,153	74.9

APPENDIX 2C

CONSERVATIVE FORECAST
FOR THE REVIEW PERIOD 2004 to 2008

Tables 1 to 4 below contain the Conservative Energy Sales and Peak Demand Forecast.

Table 1

Year	Conservative Forecast - Total Sales to each Rate Category (GWh)							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004	1,535	578	424	1,091	931	1,456	19	6,034
2005	1,601	594	439	1,130	993	1,452	19	6,227
2006	1,679	613	452	1,162	1,055	1,452	19	6,432
2007	1,767	634	463	1,192	1,068	1,452	19	6,595
2008	1,861	655	474	1,219	1,074	1,456	19	6,757

Table 2

Year	Conservative Forecast - Total Total of Monthly Demands of each Rate Category (MVA)							
	Rate-A	Rate-B	Rate-D1	Rate-D2	Rate-D3	Rate-E	Rate-S	Total
2004			1,449	3,151	1,716	3,228		9,544
2005			1,501	3,261	1,969	3,228		9,959
2006			1,544	3,344	2,125	3,228		10,241
2007			1,583	3,423	2,149	3,228		10,383
2008			1,620	3,478	2,149	3,228		10,475

Table 3

Year	Conservative Forecast - Total Units Sent Out (USO) to each Area (GWh)						Losses	
	North	South	East	Central	Tobago	Total	% USO	% Sales
2004	1,464	1,233	1,172	2,522	182	6,574	8.2	8.9
2005	1,525	1,276	1,233	2,558	193	6,784	8.2	9.0
2006	1,598	1,323	1,245	2,643	205	7,014	8.3	9.0
2007	1,666	1,374	1,256	2,686	218	7,200	8.4	9.2
2008	1,740	1,427	1,267	2,720	230	7,384	8.5	9.3

Table 4

Year	Conservative Forecast - Coincident Demand in each Area (MW)					System Demand (MW)	Load Factor
	North	South	East	Central	Tobago	Total	(%)
2004	207	177	165	417	33	999	74.9
2005	216	184	174	423	35	1,032	75.1
2006	227	190	176	438	37	1,068	75.0
2007	236	198	177	446	39	1,096	75.0
2008	246	205	178	450	41	1,120	75.0

APPENDIX 3

LOAD RESEARCH PROGRAMME

Load Research is the measurement and analysis of demand and energy usage patterns of the various classes of customers served by an electric utility. The purpose of this research is to provide complete and reliable data on general characteristics of these customer groups, which include load composition, load shapes and customer demographics, attitudes and preferences. The basic customer and load research programme is designed to collect detailed load and demographic data from a representative sample of customers, usually all major rate classes. The sample is then used to determine the characteristics of the population from which the sample was drawn[1].

This information is essential for correctly assessing and allocating costs of service for tariff setting and rate design, system planning, load forecasting, engineering, defining target energy conservation markets and evaluating Demand Side Management programme impact. Such research would provide a sound, transparent and verifiable basis for management decision-making that would promote confidence and increase efficiency.

Many utility departments are required to work together to meet the goals and objectives of the programme and it is essential to understand how data will be used before embarking upon data collection efforts.

The load research function is non-existent in T&TEC at present but it is recognized that this deficiency must be addressed if the benefits cited above are to be realised. To achieve this, a dedicated team must be assembled to design, plan and administer the programme and to coordinate the efforts of other T&TEC departments.

Metering hardware and associated software applications must also be acquired to facilitate data collection, management and analysis. The services of consultants with experience in the load research field will be required initially to establish the load research function and assist with the setting up of a programme.

Equipment costs are estimated below.

- 2004 – TT$ 150,000 Pilot project requiring a limited quantity of metering equipment.
- 2005 – TT$1,850,000 Major metering equipment purchase.

[1] Raymond Logan and Richard Brown, “Load Research and its Application in Load Forecasting at Jamaica Public Service Company”.

APPENDIX 4

SUBSTATION LOAD MONITORING

This project is intended to fill an information gap that currently exists in T&TEC's system planning and operations activities. At present, peak distribution substation and feeder demands are measured once monthly. Both the quality and frequency of these data are however woefully inadequate for reliable system planning and operations. This situation results in instances of large capacity surpluses in some areas while in others capacity shortfalls exist.

Having a constant stream of accurate system demand data will permit efficient planning of the transmission and distribution systems, so that installed plant is utilized optimally, excessive capacity margins are avoided and capacity deficiencies are eliminated. The timing of system reinforcements or new developments could then be defined more precisely, so that capital investments may be focused on areas where it is most needed and where the net benefits are maximized.

Another important aspect of this project is the replacement of existing, and in many cases non-functional, analog substation metering with updated digital equipment. This modern metering equipment will also provide electric power quality monitoring as well as facilitate remote monitoring and control of substation circuit breakers. Monitoring power quality will better enable T&TEC to understand power disturbances that may result in customer equipment damage, and provide information that could assist in identifying the causes and minimizing the effects of these events.

In the information age, the data and functionality provided by this new metering are keys to the reliable and efficient operation of a viable electric utility.

The estimated cost of outfitting all of T&TEC's distribution substations with this new equipment is as follows:

Year	2004	2005	2006	Total
Cost $M	1.2	2.0	2.0	5.2

APPENDIX 5A

BALANCE SHEET AS AT 2001-12-31

DESCRIPTION	2001 $'000
ASSETS	
Non-current Assets	
Property, plant and equipment	1,162,213
Investment in subsidiary	246,330
Convertible redeemable debenture stock	256,006
	1,664,549
Current Assets	
Inventories	77,554
Accounts receivable	329,048
Cash and cash equivalents	75,440
	482,042
Total Assets	2,146,591
EQUITY AND LIABILITIES	
Capital and Reserves	
Capital funds	1,368,114
Reserves	178,320
Accumulated deficit	(861,573)
	684,861
Non-current Liabilities	
Customers' service deposits	24,984
Medium and long term financing	637,330
Retirement benefit obligations	81,924
	744,238
Current Liabilities	
Bank advances	118,463
Short-term loan	11,703
Medium and long-term financing	14,257
Accounts payable	465,105
Due to subsidiary	107,964
	717,492
Total Equity and Liabilities	2,146,591

APPENDIX 5B

REVENUE AND EXPENDITURE ACCOUNT

DESCRIPTION	2001 $'000
Revenue	1,220,757
Expenditure	
Generation	1,021,307
Transmission and distribution	189,142
Administrative and general	98,369
Depreciation	47,634
	1,356,452
Loss from Operations	(135,695)
Interest and finance costs	(116,402)
Dividend from subsidiary	100,283
Other income	30,738
Net Loss	(121,076)

APPENDIX 5C

STATEMENT OF FIXED ASSETS AS AT 31ST DECEMBER 2001

Fixed Asset Summary	Opening Net Book Value (NBV)	Additions	Transfers / Adjustment	Depreciation Charge	Closing NBV
	$'000	$'000	$'000	$'000	$'000
Freehold /Leasehold Land	12,889	0	0	106	12,783
Structures	40,106	0	12,439	2,904	49,641
Equipment	732,868	0	128,504	52,123	809,249
Work in Progress	259,171	172,312	(140,943)	0	290,540
	1,045,034	172,312	0	55,133	1,162,213

	Original Cost	Accumulated Depreciation	Closing NBV
	$'000	$'000	$'000
Freehold /Leasehold Land	19,243	6,460	12,783
Structures	91,729	42,088	49,641
Equipment	1,379,240	569,991	809,249
Work in Progress	290,540	0	290,540
	1,780,752	618,539	1,162,213

APPENDIX 6A

BALANCE SHEET AS AT 2003-12-31

DESCRIPTION	2003 $'000	2002 $'000
ASSETS		
Non-current Assets		
Property, plant and equipment	1,315,643	1,237,062
Investment in subsidiary	246,330	246,330
Convertible redeemable debenture stock	234,545	246,285
Retirement benefit asset	227,565	-
	2,024,083	1,729,677
Current Assets		
Inventories	81,496	86,867
Accounts receivable	373,527	402,955
Cash and cash equivalents	68,321	144,964
	523,344	634,786
Total Assets	2,547,427	2,364,463
EQUITY AND LIABILITIES		
Capital and Reserves		
Capital funds	1,368,114	1,368,114
Reserves	195,725	184,757
Accumulated deficit	(645,173)	(955,458)
	918,666	597,413
Non-current Liabilities		
Customers' service deposits	29,773	26,950
Medium and long term financing	1,111,294	708,992
Retirement benefit obligations	9,395	119,076
	1,150,462	855,018
Current Liabilities		
Bank advances	63,184	65,965
Medium and long-term financing	79,016	44,257
Accounts payable	290,496	700,978
Due to subsidiary	45,603	100,832
	478,299	912,032
Total Equity and Liabilities	2,547,427	2,364,463

APPENDIX 6B

REVENUE AND EXPENDITURE ACCOUNT 2003-12-31

DESCRIPTION	2003 $'000	2002 $'000
Revenue	1,439,485	1,338,909
Expenditure		
Generation	1,155,031	1,082,042
Transmission and distribution	206,707	189,105
Administrative and general	96,478	115,583
Depreciation	72,669	52,117
	1,530,885	1,438,847
Deficit from Operations	(91,400)	(99,938)
Interest and finance costs	(96,771)	(107,128)
Dividend from subsidiary	113,292	98,754
Other income	47,918	51,579
Net Deficit Before Retirement Benefit Obligations	(26,961)	(56,733)
Net decrease/(increase) in retirement benefit obligations	337,246	(37,152)
Net Surplus/(Deficit) For The Year	310,285	(93,885)

APPENDIX 6C

ANALYSIS OF INCOME FOR THE PERIOD ENDED 2003-12-31

DESCRIPTION	2003 $'000	2002 $ '000
Rate A Residential	340,155	310,249
Rate B Commercial	136,576	125,514
Rate D1 Industrial	139,929	128,076
Rate D2 Industrial	337,223	312,778
Rate D3 Industrial	186,542	172,738
Rate E Industrial	275,346	267,498
Rate S Street Lighting	23,714	22,056
	1,439,485	1,338,909
OTHER INCOME		
Reconnection Re: Non-payment	2,650	2,422
Change or Reposition Meter&/or Secondaries	504	434
Pole Rentals - TSTT	11,521	21,731
Miscellaneous Revenue	12,321	5,850
Interest on Bank Accounts	453	594
Investment Income	3,090	2,456
Major Contracting	8,756	8,529
Bad Debt Recovered	0	0
Penalties on Power Purchases	0	0
Pole Rentals - Cable TV	8,865	8,297
Revenue Protection Programme - Admin. Charges	314	277
Common Services	(874)	0
Sale of Assets	318	989
	47,918	51,579

APPENDIX 6D

ANALYSIS OF EXPENDITURE FOR THE PERIOD ENDED 2003-12-31

	2003 $ '000	2002 $ '000
CONVERSION COST	705,389	686,659
GENERATION		
Power Generation		
Fuel	442,819	391,021
Head Office Engineering	0	0
Other Expenses	40	6
	442,859	391,027
Internal Generation		
Operations	5,141	3,143
Maintenance	1,211	898
Head Office Engineering	82	113
Rates, Taxes, Insurance	350	201
	6,783	4,355
TOTAL GENERATION	1,155,031	1,082,041
TRANSMISSION		
Maintenance	3,323	2,279
Head Office Engineering	7,483	7,389
	10,806	9,669
DISTRIBUTION		
Operations	97,706	93,538
Maintenance	59,991	56,039
Head Office Engineering	4,825	4,873
Commercial	22,385	20,673
Rates, Taxes, Insurance	10,993	4,313
	195,901	179,436
TOTAL TRANSMISSION & DISTRIBUTION	206,707	189,105
ADMINISTRATIVE & GENERAL		
Board	355	355
General Management	(4,990)	11,785
Accounts	14,248	33,868
Building Maintenance & Services	4,893	3,219
Commercial - Head Office	9,550	9,350
Human Resources	6,233	6,982
Information Systems	12,241	12,170
Internal Audit	2,063	2,001
Legal	1,112	1,233
Management Accounting	3,981	3,239
Pension Plan Administration	8,141	7,972
Public Relations	8,083	5,177
Risk Management	4,645	593
Safety	1,825	1,693
Secretarial	849	1,851
Security	11,089	10,049
Supplies	10,672	3,213
Rates, Taxes, Insurance	1,488	835
TOTAL ADMINISTRATIVE & GENERAL	96,478	115,583
Depreciation	72,669	52,117
Interest and Finance Costs	(96,771)	(107,128)

APPENDIX 7A

COST OF SERVICE STUDY

SUMMARY OF RESULTS 2001

Line No.	Description	Total Company	Bases of Allocation	Domestic Rate A	Commercial Rate B	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate E	Street Lighting
	OPERATING EXPENSES:	$		$	$	$	$	$	$	$
1	Bulk Power & Generation	1,018,243,599	AET & ET	262,013,814	106,622,084	95,757,435	209,184,624	119,571,822	220,965,319	4,128,502
2	Transmission	7,144,515	AET & ET	1,834,999	746,721	711,919	1,516,410	810,981	1,493,439	30,045
3	Distribution	98,146,624	AED & DCL	66,846,476	11,351,285	5,583,086	11,780,086	2,089,124	34,231	462,256
4	Administrative & General	83,809,585	SAW	55,217,925	9,557,985	4,513,214	8,958,877	1,784,582	615,270	3,161,677
5	Customer Accounts & Services	33,989,934	CAS	28,768,771	4,088,825	773,838	322,185	12,848	988	22,479
6	Total Operating Expenses	1,241,334,257		414,681,985	132,366,900	107,339,492	231,762,182	124,269,357	223,109,247	7,804,959
	DEPRECIATION EXPENSES:									
7	Generation	462,536	AET	118,798	48,343	46,090	98,172	52,503	96,685	1,945
8	Transmission	12,108,651	AET	3,109,988	1,265,557	1,206,573	2,570,039	1,374,466	2,531,107	50,921
9	Distribution	31,160,060	AED, DCL, SP & MET	17,016,216	3,776,902	2,466,433	5,311,616	941,378	38	1,647,441
10	Administrative & General	3,903,125	SAW	2,571,573	445,128	210,186	417,227	83,110	28,654	147,244
11	Total Depreciation Expenses	47,634,372		22,816,575	5,535,930	3,929,282	8,397,054	2,451,457	2,656,484	1,847,551
	TAXES AND OTHER DUTIES:									
12	Generation	292,200		75,049	30,540	29,116	62,019	33,168	61,079	1,229
13	Transmission	0		0	0	0	0	0	0	0
14	Distribution	7,039,113	AED, DCL & SP	2,596,841	1,056,739	930,238	2,049,816	365,068	0	40,398
15	Administrative & General	1,060,216	SAW	698,523	120,911	57,093	113,332	22,575	7,783	39,996
16	Total Taxes & Other Duties	8,391,529		3,370,413	1,208,190	1,016,447	2,225,167	420,811	68,862	81,623
	COST OF PROVIDING ADEQUATE MAINTENANCE & INTEREST PAYMENT ON BORROWINGS :									
	(i) Maintenance Expenses:									
17	Generation	2,770,953	AET	711,692	289,611	276,113	588,130	314,534	579,220	11,653
18	Transmission	2,151,871	AET	552,687	224,907	214,424	456,731	244,261	449,812	9,049
19	Distribution	54,167,300	AED, DCL, SP & MET	29,077,026	5,845,445	3,493,901	7,500,901	1,327,931	19	6,922,026
20	(ii) Interest Expenses	115,268,000	RATE BASE ALLOCATOR	55,560,382	13,089,563	9,070,727	19,308,975	6,441,623	8,271,668	3,523,539
21	(iii) Loss / (Gain) on Exchange	1,134,100	RATE BASE ALLOCATOR	546,648	128,786	89,245	189,977	63,378	81,383	34,667
22	**Total Maintenance & Interest**	175,492,224		86,448,435	19,578,311	13,144,410	28,044,714	8,391,727	9,382,102	10,500,935
23	**TOTAL EXPENSES**	**1,472,852,382**		**527,317,408**	**158,689,331**	**125,429,632**	**270,429,117**	**135,533,352**	**235,216,696**	**20,235,068**
	PERCENTAGE RETURN ON RATE BASE:									
24	Rate Base	1,402,777,541		676,153,450	159,296,118	110,388,067	234,984,528	78,392,649	100,663,754	42,880,428
25	Return at 7.5%	105,208,316		50,711,509	11,947,209	8,279,105	17,623,840	5,879,449	7,549,782	3,216,032
26	**TOTAL COST OF SERVICE**	**1,578,060,698**		**578,028,917**	**170,636,540**	**133,708,737**	**288,052,957**	**141,412,801**	**242,766,478**	**23,451,100**
	REVENUE REQUIREMENTS :									
27	Total Cost of Service	1,578,060,698		578,028,917	170,636,540	133,708,737	288,052,957	141,412,801	242,766,478	23,451,100
28	Less : Miscellaneous Revenues	131,021,314		46,188,590	15,043,732	11,782,508	26,659,141	11,370,135	18,650,535	1,326,673
29	**Revenue required from Sales(with 7.5% Rate Base)**	**1,447,039,384**		**531,840,327**	**155,592,808**	**121,926,229**	**261,393,816**	**130,042,666**	**224,115,943**	**22,124,427**
30	Present Rates Revenue	1,220,757,399		287,298,640	118,640,891	123,293,315	289,718,457	146,316,275	234,267,502	21,222,319
31	**REVENUE SURPLUS / (DEFICIENCY)**	**(226,281,985)**		**(244,541,687)**	**(36,951,917)**	**1,367,086**	**28,324,641**	**16,273,609**	**10,151,559**	**(902,108)**
32	**PERCENT SURPLUS / (DEFICIENCY) %**	**(18.54)**		**(85.12)**	**(31.15)**	**1.11**	**9.78**	**11.12**	**4.33**	**(4.25)**
33	Number of Customers	329,921		296,995	30,284	1,566	652	26	2	403
34	Present Avg Mthly Bill / Customer($)	N/A		80.61	326.47	6,560.95	37,029.46	468,962.42	9,761,145.92	4,388.40
35	Deficiency per Bill per Customer ($)	N/A		**(68.62)**	**(101.68)**	72.75	3,620.23	52,159.00	422,981.63	(186.54)
36	kWh Sold	5,148,608,385		1,285,003,284	522,910,660	417,015,126	960,416,263	665,864,184	1,278,593,263	18,805,605
37	Present Revenue per kWh (c)	23.71		22.36	22.69	29.57	30.17	21.97	18.32	112.85
38	Computed Cost per kWh (c)	28.11		41.39	29.76	29.24	27.22	19.53	17.53	117.65
39	**Gain / (Loss) per kWh Sold (c)**	**(4.40)**		**(19.03)**	**(7.07)**	**0.33**	**2.95**	**2.44**	**0.79**	**(4.80)**
40	**Return on Rate Base (%)**	**(8.63)**		**(28.67)**	**(15.70)**	**8.74**	**19.55**	**28.26**	**17.58**	**5.40**

Note

(I) Return on Rate Base is Present Rates Revenue plus Miscellaneous Revenues less Total Expenses expressed as a percentage of Rate Base.

APPENDIX 7B

COST OF SERVICE STUDY

SUMMARY FORECAST 2004

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
	OPERATING EXPENSES:	$		$	$	$	$	$	$	$	$	$	$	$
1	Bulk Power & Generation	1,224,870,026	AET & ET	333,007,909	150,169,553	41,419,184	101,145,562	159,197,743	53,317,397	89,163,087	36,536,032	36,680,049	219,879,308	4,354,202
2	Transmission	8,080,699	AET & ET	2,236,470	1,043,582	324,267	650,366	1,041,055	336,733	552,790	238,089	222,542	1,404,221	30,585
3	Distribution	113,262,110	AED & DCL	52,761,883	18,522,618	5,447,466	11,088,178	17,813,021	5,814,305	70,051	24,573	26,950	170,986	1,522,078
4	Administrative & General	103,660,768	SAW	69,831,389	11,808,446	3,763,164	3,982,183	7,226,767	2,108,193	252,473	88,566	97,132	616,257	3,886,193
5	Customer Accounts & Services	44,309,666	CAS	38,142,473	5,437,363	55,192	500,273	129,822	2,178	8,524	3,934	656	656	28,596
6	Total Operating Expenses	1,494,183,269		495,980,124	186,981,562	51,009,273	117,366,562	185,408,407	61,578,806	90,046,925	36,891,195	37,027,329	222,071,428	9,821,654
	DEPRECIATION EXPENSES:													
7	Generation	779,990	AET	215,875	100,732	31,300	62,777	100,488	32,503	53,358	22,982	21,481	135,542	2,952
8	Transmission	20,440,550	AET	5,657,268	2,639,795	820,249	1,645,135	2,633,402	851,783	1,398,311	602,259	562,931	3,552,051	77,365
9	Distribution	52,597,024	AED, DCL, SP & MET	29,331,345	7,307,130	1,626,542	3,872,947	5,797,097	1,897,212	3,788	1,748	291	291	2,758,631
10	Administrative & General	6,593,726	SAW	4,441,883	751,120	239,370	253,301	459,685	134,099	16,060	5,634	6,178	39,199	247,196
11	Total Depreciation Expenses	80,411,289		39,646,371	10,798,777	2,717,461	5,834,160	8,990,672	2,915,597	1,471,517	632,623	590,882	3,727,084	3,086,145
	TAXES AND OTHER DUTIES:													
12	Generation	424,529		117,496	54,826	17,036	34,168	54,693	17,691	29,041	12,508	11,691	73,772	1,607
13	Transmission	0		0	0	0	0	0	0	0	0	0	0	0
14	Distribution	9,846,673	AED, DCL & SP	3,890,468	1,776,615	513,112	1,163,332	1,842,061	609,367	0	0	0	0	51,718
15	Administrative & General	2,183,744	SAW	1,471,086	248,760	79,276	83,890	152,241	44,412	5,319	1,866	2,046	12,982	81,868
16	Total Taxes & Other Duties	12,454,946		5,479,049	2,080,201	609,424	1,281,389	2,048,995	671,470	34,360	14,374	13,738	86,755	135,192
	COST OF PROVIDING ADEQUATE MAINTENANCE & INTEREST PAYMENT ON BORROWINGS :													
	(i) Maintenance Expenses:													
17	Generation	2,664,937	AET	737,566	344,163	106,940	214,484	343,330	111,051	182,305	78,520	73,392	463,099	10,087
18	Transmission	4,217,639	AET	1,167,303	544,687	169,248	339,452	543,368	175,754	288,523	124,268	116,153	732,919	15,963
19	Distribution	65,049,338	AED, DCL, SP & MET	35,644,169	7,977,587	1,644,326	3,765,084	5,789,696	1,905,051	1,300	600	100	100	8,321,326
20	(ii) Interest Expenses	90,954,923	RATE BASE ALLOCATOR	45,169,066	10,277,221	5,289,270	5,298,028	10,121,311	2,981,686	2,179,969	743,224	847,091	5,304,795	2,743,260
21	(iii) Loss / (Gain) on Exchange	(2,000,000)	RATE BASE ALLOCATOR	(993,219)	(225,985)	(116,305)	(116,498)	(222,557)	(65,564)	(47,935)	(16,343)	(18,627)	(116,647)	(60,321)
22	**Total Maintenance & Interest**	160,886,837		81,724,885	18,917,673	7,093,478	9,500,551	16,575,149	5,107,978	2,604,162	930,269	1,018,110	6,384,266	11,030,315
23	**TOTAL EXPENSES**	**1,747,936,341**	**1,747,936,336**	**622,830,430**	**218,778,213**	**61,429,636**	**133,982,662**	**213,023,223**	**70,273,851**	**94,156,964**	**38,468,461**	**38,650,059**	**232,269,532**	**24,073,305**

SUMMARY FORECAST 2004

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
	PERCENTAGE RETURN ON RATE BASE:													
24	Rate Base	1,594,015,721		791,603,119	180,111,772	92,696,243	92,849,734	177,379,395	52,255,060	38,204,695	13,025,246	14,845,563	92,968,321	48,076,565
25	Return at 7.5%	119,551,179		59,370,234	13,508,383	6,952,218	6,963,730	13,303,455	3,919,130	2,865,352	976,893	1,113,417	6,972,624	3,605,742
26	**TOTAL COST OF SERVICE**	**1,867,487,520**		**682,200,664**	**232,286,596**	**68,381,854**	**140,946,392**	**226,326,678**	**74,192,981**	**97,022,316**	**39,445,354**	**39,763,476**	**239,242,156**	**27,679,047**
	REVENUE REQUIREMENTS :													
27	Total Cost of Service	1,867,487,520		682,200,664	232,286,596	68,381,854	140,946,392	226,326,678	74,192,981	97,022,316	39,445,354	39,763,476	239,242,156	27,679,047
28	Less : Miscellaneous Revenues	149,239,118		55,097,718	16,805,547	9,564,660	9,944,658	20,783,296	5,533,035	7,485,973	2,405,970	2,891,469	17,415,816	1,310,974
29	**Revenue required from Sales(with 7.5% Rate Base)**	**1,718,248,402**		**627,102,946**	**215,481,049**	**58,817,194**	**131,001,734**	**205,543,382**	**68,659,946**	**89,536,343**	**37,039,384**	**36,872,007**	**221,826,340**	**26,368,073**
30	Present Rates Revenue	1,353,892,583		345,536,663	139,148,296	106,732	177,639,621	208,917,498	61,586,630	94,807,932	42,693,085	36,856,793	225,581,050	21,018,283
31	**REVENUE SURPLUS / (DEFICIENCY)**	**(364,355,819)**		**(281,566,283)**	**(76,332,753)**	**(58,710,462)**	**46,637,887**	**3,374,116**	**(7,073,316)**	**5,271,589**	**5,653,701**	**(15,214)**	**3,754,710**	**(5,349,790)**
32	**PERCENT SURPLUS / (DEFICIENCY) %**	**(26.91)**		**(81.49)**	**(54.86)**	**(55,007.41)**	**26.25**	**1.62**	**(11.49)**	**5.56**	**13.24**	**(0.04)**	**1.66**	**(25.45)**
33	Number of Customers	345,936		311,789	32,206	544	763	198	9	13	6	1	1	406
34	Present Avg Mthly Bill / Customer($)	N/A		92.35	360.05	16.35	19,401.44	87,928.24	570,246.57	607,743.15	592,959.51	3,071,399.42	18,798,420.83	4,314.10
35	Deficiency per Bill per Customer ($)	N/A		**(75.26)**	**(197.51)**	**(8,993.64)**	5,093.70	1,420.08	(65,493.66)	33,792.24	78,523.62	(1,267.81)	312,892.52	(1,098.07)
36	kWh Sold	6,121,000,000		1,560,000,000	666,978,000	146,022,000	503,948,000	775,052,000	272,000,000	521,000,000	200,000,000	220,000,000	1,237,000,000	19,000,000
37	Present Revenue per kWh (c)	22.12		22.15	20.86	0.07	35.25	26.96	22.64	18.20	21.35	16.75	18.24	110.62
38	Computed Cost per kWh (c)	28.07		40.20	32.31	40.28	26.00	26.52	25.24	17.19	18.52	16.76	17.93	138.78
39	**Gain / (Loss) per kWh Sold (c)**	**(5.95)**		**(18.05)**	**(11.45)**	**(40.21)**	**9.25**	**0.44**	**(2.60)**	**1.01**	**2.83**	**(0.01)**	**0.31**	**(28.16)**
40	**Return on Rate Base (%)**	**(15.36)**		**(28.07)**	**(34.88)**	**(55.84)**	**57.73**	**9.40**	**(6.04)**	**21.30**	**50.91**	**7.40**	**11.54**	**(3.63)**

Note

(I) Return on Rate Base is Present Rates Revenue plus Miscellaneous Revenues less Total Expenses expressed as a percentage of Rate Base.

APPENDIX 7C

COST OF SERVICE STUDY

SUMMARY FORECAST 2005

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E Ispat	Street Lighting
	OPERATING EXPENSES:	$		$	$		$	$	$	$	$	$	$	$
1	Bulk Power & Generation	1,330,832,199	AET & ET	358,709,340	161,236,666	44,767,836	109,226,099	171,941,642	60,279,158	115,514,663	38,402,392	37,899,777	228,310,090	4,544,536
2	Transmission	8,007,959	AET & ET	2,200,460	1,022,666	319,081	641,745	1,026,989	341,655	652,756	228,951	210,389	1,334,139	29,127
3	Distribution	112,995,091	AED & DCL	52,517,048	18,382,942	5,390,345	11,081,609	17,792,765	6,055,879	71,151	26,174	25,501	161,370	1,490,308
4	Administrative & General	108,220,743	SAW	73,115,755	12,320,058	3,841,180	4,093,399	7,451,108	2,269,905	271,143	99,746	97,179	614,952	4,046,320
5	Customer Accounts & Services	44,774,367	CAS	38,546,622	5,494,119	55,342	500,781	130,722	2,812	9,755	4,553	651	651	28,359
6	Total Operating Expenses	1,604,830,359		525,089,226	198,456,451	54,373,784	125,543,633	198,343,226	68,949,409	116,519,467	38,761,816	38,233,496	230,421,202	10,138,650
	DEPRECIATION EXPENSES:													
7	Generation	797,358	AET	219,101	101,828	31,771	63,899	102,258	34,019	64,995	22,797	20,949	132,841	2,900
8	Transmission	20,895,724	AET	5,741,814	2,668,513	832,601	1,674,549	2,679,794	891,505	1,703,281	597,417	548,983	3,481,262	76,004
9	Distribution	53,768,266	AED, DCL, SP & MET	29,952,031	7,427,641	1,652,907	3,961,496	5,930,249	2,023,031	4,386	2,047	292	292	2,813,893
10	Administrative & General	6,740,556	SAW	4,554,033	767,358	239,249	254,958	464,094	141,382	16,888	6,213	6,053	38,302	252,026
11	Total Depreciation Expenses	82,201,905		40,466,979	10,965,340	2,756,528	5,954,902	9,176,395	3,089,937	1,789,551	628,474	576,277	3,652,698	3,144,823
	TAXES AND OTHER DUTIES:													
12	Generation	425,773		116,996	54,374	16,965	34,121	54,604	18,165	34,706	12,173	11,186	70,934	1,549
13	Transmission	0		0	0	0	0	0	0	0	0	0	0	0
14	Distribution	10,143,960	AED, DCL & SP	6,853,430	1,154,808	360,049	383,691	698,422	212,767	25,415	9,350	9,109	57,642	379,278
15	Administrative & General	2,287,922	SAW	1,545,759	260,461	81,207	86,540	157,526	47,989	5,732	2,109	2,054	13,001	85,544
16	Total Taxes & Other Duties	12,857,655		8,516,185	1,469,643	458,222	504,351	910,551	278,921	65,854	23,631	22,350	141,577	466,371
	COST OF PROVIDING ADEQUATE MAINTENANCE & INTEREST PAYMENT ON BORROWINGS :													
	(i) Maintenance Expenses:													
17	Generation	3,064,945	AET	842,198	391,412	122,124	245,620	393,067	130,764	249,834	87,628	80,524	510,625	11,148
18	Transmission	4,810,930	AET	1,321,967	614,386	191,694	385,540	616,983	205,256	392,155	137,546	126,395	801,509	17,499
19	Distribution	61,649,094	AED, DCL, SP & MET	33,750,595	7,521,144	1,549,117	3,571,523	5,490,946	1,883,135	1,396	651	93	93	7,880,401
20	(ii) Interest Expenses	123,000,000	RATE BASE ALLOCATOR	62,027,878	13,916,757	6,894,938	6,963,383	13,344,139	4,078,589	3,032,553	1,089,629	1,101,763	6,877,699	3,672,673
21	(iii) Loss / (Gain) on Exchange	0	RATE BASE ALLOCATOR	0	0	0	0	0	0	0	0	0	0	0
22	**Total Maintenance & Interest**	192,524,969		97,942,639	22,443,699	8,757,873	11,166,066	19,845,134	6,297,744	3,675,938	1,315,455	1,308,775	8,189,926	11,581,721
23	**TOTAL EXPENSES**	**1,892,414,888**		**672,015,028**	**233,335,133**	**66,346,407**	**143,168,952**	**228,275,307**	**78,616,011**	**122,050,810**	**40,729,376**	**40,140,897**	**242,405,403**	**25,331,565**

SUMMARY FORECAST 2005

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E Ispat	Street Lighting
	PERCENTAGE RETURN ON RATE BASE:													
24	Rate Base	1,939,922,212		978,286,653	219,491,267	108,745,063	109,824,568	210,460,089	64,326,387	47,828,588	17,185,329	17,376,706	108,473,183	57,924,388
25	Return at 7. 5%	145,494,166		73,371,499	16,461,845	8,155,880	8,236,843	15,784,507	4,824,479	3,587,144	1,288,900	1,303,253	8,135,489	4,344,329
26	**TOTAL COST OF SERVICE**	**2,037,909,054**		**745,386,527**	**249,796,978**	**74,502,287**	**151,405,795**	**244,059,814**	**83,440,490**	**125,637,954**	**42,018,276**	**41,444,150**	**250,540,892**	**29,675,894**
	REVENUE REQUIREMENTS :													
27	Total Cost of Service	2,037,909,054		745,386,527	249,796,978	74,502,287	151,405,795	244,059,814	83,440,490	125,637,954	42,018,276	41,444,150	250,540,892	29,675,894
28	Less : Miscellaneous Revenues	151,655,885		55,776,866	17,087,770	9,683,025	10,124,057	21,249,885	5,947,033	7,854,895	2,693,702	2,851,265	17,099,159	1,288,228
29	**Revenue required from Sales(with 7.5% Rate Base)**	**1,886,253,169**		**689,609,661**	**232,709,208**	**64,819,262**	**141,281,738**	**222,809,929**	**77,493,457**	**117,783,059**	**39,324,574**	**38,592,885**	**233,441,733**	**28,387,666**
30	Present Rates Revenue	1,385,888,539		360,598,753	150,947,340	19,833,189	113,661,287	219,716,483	183,962,541	32,263,672	17,212,800	9,062,400	257,563,959	21,066,115
31	**REVENUE SURPLUS / (DEFICIENCY)**	**(500,364,630)**		**(329,010,908)**	**(81,761,868)**	**(44,986,073)**	**(27,620,451)**	**(3,093,446)**	**106,469,084**	**(85,519,387)**	**(22,111,774)**	**(29,530,485)**	**24,122,226**	**(7,321,551)**
32	**PERCENT SURPLUS / (DEFICIENCY) %**	**(36.10)**		**(91.24)**	**(54.17)**	**(226.82)**	**(24.30)**	**(1.41)**	**57.88**	**(265.06)**	**(128.46)**	**(325.86)**	**9.37**	**(34.76)**
33	Number of Customers	352,485		317,713	32,811	550	770	201	10	15	7	1	1	406
34	Present Avg Mthly Bill / Customer($)	N/A		94.58	383.38	3,005.03	12,301.01	91,093.07	1,533,021.18	179,242.62	204,914.29	755,200.00	21,463,663.25	4,323.92
35	Deficiency per Bill per Customer ($)	N/A		**(86.30)**	**(207.66)**	**(6,816.07)**	(2,989.23)	(1,282.52)	887,242.37	(475,107.71)	(263,235.41)	(2,460,873.73)	2,010,185.52	(1,502.78)
36	kWh Sold	6,413,000,000		1,610,000,000	686,128,000	151,212,000	521,879,000	802,781,000	302,000,000	656,000,000	203,000,000	220,000,000	1,241,000,000	19,000,000
37	Present Revenue per kWh (c)	21.61		22.40	22.00	13.12	21.78	27.37	60.91	4.92	8.48	4.12	20.75	110.87
38	Computed Cost per kWh (c)	29.41		42.83	33.92	42.87	27.07	27.75	25.66	17.95	19.37	17.54	18.81	149.41
39	**Gain / (Loss) per kWh Sold (c)**	**(7.80)**		**(20.43)**	**(11.92)**	**(29.75)**	**(5.29)**	**(0.38)**	**35.25**	**(13.03)**	**(10.89)**	**(13.42)**	**1.94**	**(38.54)**
40	**Return on Rate Base (%)**	**(18.29)**		**(26.13)**	**(29.75)**	**(33.87)**	**(17.65)**	**6.03**	**173.01**	**(171.30)**	**(121.17)**	**(162.44)**	**29.74**	**(5.14)**

Note

(I) Return on Rate Base is Present Rates Revenue plus Miscellaneous Revenues less Total Expenses expressed as a percentage of Rate Base.

APPENDIX 7D

COST OF SERVICE STUDY

SUMMARY FORECAST 2006

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
	OPERATING EXPENSES:	$		$	$		$	$	$	$	$	$	$	$
1	Bulk Power & Generation	1,450,320,938	AET & ET	397,206,036	175,789,865	48,255,278	119,402,366	187,641,979	65,948,383	126,797,171	39,809,335	39,468,835	245,202,674	4,799,015
2	Transmission	8,241,819	AET & ET	2,304,112	1,054,164	325,406	663,691	1,060,088	355,019	677,728	224,516	207,508	1,340,506	29,080
3	Distribution	114,103,403	AED & DCL	53,451,139	18,476,116	5,373,910	11,122,634	17,837,197	6,067,353	77,144	27,629	24,775	156,656	1,488,850
4	Administrative & General	109,164,403	SAW	74,082,184	12,413,923	3,823,948	4,074,023	7,414,909	2,196,293	293,015	104,942	94,103	595,020	4,072,046
5	Customer Accounts & Services	45,102,862	CAS	38,833,218	5,532,984	55,311	500,915	129,891	6,431	10,288	4,501	643	643	28,037
6	Total Operating Expenses	1,726,933,426		565,876,689	213,267,052	57,833,854	135,763,630	214,084,064	74,573,479	127,855,346	40,170,924	39,795,865	247,295,499	10,417,028
	DEPRECIATION EXPENSES:													
7	Generation	816,766	AET	228,338	104,468	32,248	65,772	105,055	35,182	67,163	22,250	20,564	132,844	2,882
8	Transmission	21,404,310	AET	5,983,865	2,737,702	845,092	1,723,629	2,753,087	921,998	1,760,084	583,078	538,907	3,481,345	75,522
9	Distribution	55,076,944	AED, DCL, SP & MET	30,801,447	7,577,786	1,672,257	4,038,017	6,037,612	2,066,280	4,704	2,058	294	294	2,876,195
10	Administrative & General	6,904,616	SAW	4,685,676	785,177	241,864	257,681	468,991	138,915	18,533	6,638	5,952	37,635	257,556
11	Total Depreciation Expenses	84,202,635		41,699,326	11,205,133	2,791,460	6,085,099	9,364,745	3,162,376	1,850,484	614,023	565,717	3,652,118	3,212,155
	TAXES AND OTHER DUTIES:													
12	Generation	429,681		120,123	54,958	16,965	34,601	55,267	18,509	35,333	11,705	10,818	69,886	1,516
13	Transmission	0		0	0	0	0	0	0	0	0	0	0	0
14	Distribution	10,235,400	AED, DCL & SP	6,946,044	1,163,946	358,538	381,986	695,232	205,927	27,473	9,839	8,823	55,790	381,800
15	Administrative & General	2,307,291	SAW	1,565,795	262,380	80,823	86,108	156,721	46,421	6,193	2,218	1,989	12,576	86,066
16	Total Taxes & Other Duties	12,972,371		8,631,963	1,481,284	456,326	502,695	907,220	270,857	68,999	23,762	21,630	138,252	469,383
	COST OF PROVIDING ADEQUATE													
	MAINTENANCE & INTEREST PAYMENT													
	ON BORROWINGS :													
	(i) Maintenance Expenses:													
17	Generation	3,090,595	AET	864,018	395,300	122,024	248,877	397,522	133,128	254,141	84,191	77,813	502,676	10,905
18	Transmission	4,939,345	AET	1,380,861	631,763	195,017	397,752	635,314	212,764	406,164	134,553	124,360	803,369	17,428
19	Distribution	62,205,586	AED, DCL, SP & MET	34,166,171	7,560,648	1,543,869	3,586,339	5,507,018	1,893,583	1,474	645	92	92	7,945,655
20	(ii) Interest Expenses	138,000,000	RATE BASE ALLOCATOR	70,259,561	15,596,758	7,647,358	7,706,932	14,782,996	4,388,254	3,644,793	1,274,427	1,187,490	7,411,027	4,100,403
21	(iii) Loss / (Gain) on Exchange	0	RATE BASE ALLOCATOR	0	0	0	0	0	0	0	0	0	0	0
22	**Total Maintenance & Interest**	208,235,525		106,670,610	24,184,470	9,508,268	11,939,899	21,322,850	6,627,729	4,306,572	1,493,817	1,389,756	8,717,163	12,074,390

SUMMARY FORECAST 2006

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
23	TOTAL EXPENSES	2,032,343,957		722,878,589	250,137,938	70,589,908	154,291,324	245,678,878	84,634,441	134,081,401	42,302,526	41,772,969	259,803,032	26,172,956

SUMMARY FORECAST 2006

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
	PERCENTAGE RETURN ON RATE BASE:													
24	Rate Base	2,139,112,234		1,089,080,342	241,762,435	118,540,273	119,463,718	229,148,469	68,021,506	56,497,263	19,754,654	18,407,067	114,876,939	63,559,583
25	Return at 7.5%	160,433,418		81,681,026	18,132,183	8,890,521	8,959,779	17,186,135	5,101,613	4,237,295	1,481,599	1,380,530	8,615,770	4,766,969
26	**TOTAL COST OF SERVICE**	**2,192,777,375**		**804,559,615**	**268,270,121**	**79,480,429**	**163,251,103**	**262,865,013**	**89,736,054**	**138,318,696**	**43,784,125**	**43,153,499**	**268,418,802**	**30,939,925**
	REVENUE REQUIREMENTS :													
27	Total Cost of Service	2,192,777,375		804,559,615	268,270,121	79,480,429	163,251,103	262,865,013	89,736,054	138,318,696	43,784,125	43,153,499	268,418,802	30,939,925
28	Less : Miscellaneous Revenues	153,012,445		57,045,626	17,252,940	9,674,174	10,114,298	21,219,406	5,758,394	8,480,425	2,818,957	2,768,627	16,622,177	1,257,422
29	**Revenue required from Sales(with 7.5% Rate Base)**	**2,039,764,930**		**747,513,989**	**251,017,181**	**69,806,255**	**153,136,805**	**241,645,607**	**83,977,660**	**129,838,271**	**40,965,168**	**40,384,872**	**251,796,625**	**29,682,503**
30	Present Rates Revenue	1,262,114,521		326,531,065	120,661,000	78,327,140	63,907,893	278,516,193	53,119,756	89,136,339	35,586,695	26,622,870	169,433,805	20,271,765
31	**REVENUE SURPLUS / (DEFICIENCY)**	**(777,650,409)**		**(420,982,924)**	**(130,356,181)**	**8,520,885**	**(89,228,912)**	**36,870,586**	**(30,857,904)**	**(40,701,932)**	**(5,378,473)**	**(13,762,002)**	**(82,362,820)**	**(9,410,738)**
32	**PERCENT SURPLUS / (DEFICIENCY) %**	**(61.61)**		**(128.93)**	**(108.04)**	**10.88**	**(139.62)**	**13.24**	**(58.09)**	**(45.66)**	**(15.11)**	**(51.69)**	**(48.61)**	**(46.42)**
33	Number of Customers	359,144		323,750	33,416	556	779	202	10	16	7	1	1	406
34	Present Avg Mthly Bill / Customer($)	N/A		84.05	300.91	11,739.68	6,836.53	114,899.42	442,664.63	464,251.77	423,651.13	2,218,572.50	14,119,483.75	4,160.87
35	Deficiency per Bill per Customer ($)	N/A		**(108.36)**	**(325.08)**	**1,277.11**	(9,545.24)	15,210.64	(257,149.20)	(211,989.23)	(64,029.44)	(1,146,833.46)	(6,863,568.33)	(1,931.60)
36	kWh Sold	6,656,000,000		1,683,000,000	707,849,000	155,611,000	536,998,000	825,542,000	309,000,000	693,000,000	203,000,000	220,000,000	1,303,000,000	19,000,000
37	Present Revenue per kWh (c)	18.96		19.40	17.05	50.34	11.90	33.74	17.19	12.86	17.53	12.10	13.00	106.69
38	Computed Cost per kWh (c)	30.65		44.42	35.46	44.86	28.52	29.27	27.18	18.74	20.18	18.36	19.32	156.22
39	**Gain / (Loss) per kWh Sold (c)**	**(11.69)**		**(25.02)**	**(18.41)**	**5.48**	**(16.62)**	**4.47**	**(9.99)**	**(5.88)**	**(2.65)**	**(6.26)**	**(6.32)**	**(49.53)**
40	**Return on Rate Base (%)**	**(28.85)**		**(31.15)**	**(46.42)**	**14.69**	**(67.19)**	**23.59**	**(37.86)**	**(64.54)**	**(19.73)**	**(67.26)**	**(64.20)**	**(7.31)**

Note

(I) Return on Rate Base is Present Rates Revenue plus Miscellaneous Revenues less Total Expenses expressed as a percentage of Rate Base.

APPENDIX 7E

COST OF SERVICE STUDY

SUMMARY FORECAST 2007

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
	OPERATING EXPENSES:	$		$	$	$	$	$	$	$	$	$	$	$
1	Bulk Power & Generation	1,498,151,169	AET & ET	425,890,027	184,487,344	49,389,137	125,687,017	197,323,463	67,966,636	124,583,819	38,849,800	38,857,494	240,247,987	4,868,446
2	Transmission	8,430,352	AET & ET	2,435,991	1,085,676	322,415	693,495	1,103,697	365,186	665,560	217,019	204,801	1,307,604	28,909
3	Distribution	115,054,847	AED & DCL	54,465,360	18,416,763	5,114,824	11,258,521	17,964,834	6,076,884	77,236	26,979	24,174	152,911	1,476,360
4	Administrative & General	109,324,965	SAW	74,509,181	12,456,473	3,766,164	4,002,900	7,253,310	2,204,228	291,909	101,967	91,366	577,923	4,069,546
5	Customer Accounts & Services	45,331,068	CAS	39,039,942	5,560,939	55,188	499,792	128,917	2,744	10,161	4,446	635	635	27,669
6	Total Operating Expenses	1,776,292,402		596,340,500	222,007,195	58,647,729	142,141,725	223,774,221	76,615,679	125,628,684	39,200,210	39,178,470	242,287,060	10,470,931
	DEPRECIATION EXPENSES:													
7	Generation	841,617	AET	243,189	108,385	32,187	69,233	110,184	36,457	66,444	21,665	20,446	130,540	2,886
8	Transmission	22,055,577	AET	6,373,066	2,840,357	843,506	1,814,328	2,887,505	955,403	1,741,246	567,766	535,802	3,420,967	75,632
9	Distribution	56,752,765	AED, DCL, SP & MET	31,935,823	7,722,568	1,612,371	4,181,631	6,227,406	2,110,148	4,763	2,084	298	298	2,955,376
10	Administrative & General	7,114,702	SAW	4,848,944	810,648	245,096	260,503	472,034	143,448	18,997	6,636	5,946	37,610	264,840
11	Total Depreciation Expenses	86,764,661		43,401,022	11,481,958	2,733,160	6,325,694	9,697,129	3,245,455	1,831,450	598,151	562,491	3,589,416	3,298,734
	TAXES AND OTHER DUTIES:													
12	Generation	434,186		125,460	55,915	16,605	35,717	56,843	18,808	34,278	11,177	10,548	67,345	1,489
13	Transmission	0		0	0	0	0	0	0	0	1	0	0	0
14	Distribution	10,325,569	AED, DCL & SP	7,037,274	1,176,494	355,708	378,068	685,064	208,186	27,570	9,631	8,629	54,584	384,362
15	Administrative & General	2,307,802	SAW	1,572,856	262,951	79,502	84,499	153,114	46,530	6,162	2,152	1,929	12,200	85,906
16	Total Taxes & Other Duties	13,067,557		8,735,590	1,495,360	451,816	498,284	895,021	273,524	68,011	22,961	21,106	134,129	471,757
	COST OF PROVIDING ADEQUATE													
	MAINTENANCE & INTEREST PAYMENT													
	ON BORROWINGS :													
	(i) Maintenance Expenses:													
17	Generation	3,122,784	AET	902,344	402,158	119,430	256,885	408,833	135,273	246,538	80,388	75,863	484,365	10,708
18	Transmission	4,973,397	AET	1,437,087	640,483	190,205	409,120	651,115	215,437	392,640	128,028	120,820	771,407	17,054
19	Distribution	62,762,076	AED, DCL, SP & MET	34,647,183	7,550,868	1,458,128	3,637,893	5,562,129	1,894,540	1,462	640	91	91	8,009,052
20	(ii) Interest Expenses	153,000,000	RATE BASE ALLOCATOR	78,665,163	17,384,510	8,365,842	8,404,016	16,069,668	4,899,868	4,039,196	1,374,027	1,281,242	7,992,410	4,524,058
21	(iii) Loss / (Gain) on Exchange	0	RATE BASE ALLOCATOR	0	0	0	0	0	0	0	1	0	0	0
22	**Total Maintenance & Interest**	223,858,258		115,651,777	25,978,019	10,133,605	12,707,914	22,691,745	7,145,118	4,679,836	1,583,084	1,478,016	9,248,273	12,560,873

SUMMARY FORECAST 2007

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
23	TOTAL EXPENSES	2,099,982,878		764,128,889	260,962,532	71,966,310	161,673,618	257,058,117	87,279,777	132,207,981	41,404,406	41,240,083	255,258,879	26,802,294

SUMMARY FORECAST 2007

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E 5	Street Lighting
	PERCENTAGE RETURN ON RATE BASE:													
24	Rate Base	2,336,579,630		1,201,355,674	265,492,103	127,761,146	128,344,139	245,412,157	74,829,626	61,685,637	20,983,817	19,566,822	122,058,186	69,090,335
25	Return at 7.5%	175,243,472		90,101,676	19,911,908	9,582,086	9,625,810	18,405,912	5,612,222	4,626,423	1,573,786	1,467,512	9,154,364	5,181,775
26	**TOTAL COST OF SERVICE**	**2,275,226,350**		**854,230,565**	**280,874,440**	**81,548,396**	**171,299,428**	**275,464,029**	**92,891,999**	**136,834,404**	**42,978,192**	**42,707,595**	**264,413,243**	**31,984,069**
	REVENUE REQUIREMENTS :													
27	Total Cost of Service	2,275,226,350		854,230,565	280,874,440	81,548,396	171,299,428	275,464,029	92,891,999	136,834,404	42,978,192	42,707,595	264,413,243	31,984,069
28	Less : Miscellaneous Revenues	154,369,003		58,207,774	17,519,781	9,666,259	10,087,098	21,166,351	5,904,499	8,645,935	2,784,860	2,743,242	16,433,981	1,209,227
29	**Revenue required from Sales(with 7.5% Rate Base)**	**2,120,857,347**		**796,022,791**	**263,354,659**	**71,882,137**	**161,212,330**	**254,297,678**	**86,987,500**	**128,188,469**	**40,193,332**	**39,964,353**	**247,979,262**	**30,774,842**
30	Present Rates Revenue	1,290,918,764		343,730,766	125,059,896	112,214,884	38,706,669	277,819,449	53,186,948	90,659,554	35,299,390	26,309,164	167,689,786	20,242,258
31	**REVENUE SURPLUS / (DEFICIENCY)**	**(829,938,583)**		**(452,292,025)**	**(138,294,763)**	**40,332,747**	**(122,505,661)**	**23,521,771**	**(33,800,552)**	**(37,528,915)**	**(4,893,942)**	**(13,655,189)**	**(80,289,476)**	**(10,532,584)**
32	**PERCENT SURPLUS / (DEFICIENCY) %**	**(64.29)**		**(131.58)**	**(110.58)**	**35.94**	**(316.50)**	**8.47**	**(63.55)**	**(41.40)**	**(13.86)**	**(51.90)**	**(47.88)**	**(52.03)**
33	Number of Customers	365,755		329,739	34,023	562	787	203	10	16	7	1	1	406
34	Present Avg Mthly Bill / Customer($)	N/A		86.87	306.31	16,639.22	4,098.55	114,047.39	443,224.57	472,185.18	420,230.83	2,192,430.33	13,974,148.83	4,154.81
35	Deficiency per Bill per Customer ($)	N/A		**(114.31)**	**(338.73)**	**5,980.54**	(12,971.80)	9,655.90	(281,671.27)	(195,463.10)	(58,261.22)	(1,137,932.39)	(6,690,789.63)	(2,161.86)
36	kWh Sold	6,804,000,000		1,768,000,000	731,171,000	159,549,000	550,709,000	847,571,000	309,000,000	693,000,000	203,000,000	220,000,000	1,303,000,000	19,000,000
37	Present Revenue per kWh (c)	18.97		19.44	17.10	70.33	7.03	32.78	17.21	13.08	17.39	11.96	12.87	106.54
38	Computed Cost per kWh (c)	31.17		45.02	36.02	45.05	29.27	30.00	28.15	18.50	19.80	18.17	19.03	161.97
39	**Gain / (Loss) per kWh Sold (c)**	**(12.20)**		**(25.58)**	**(18.92)**	**25.28**	**(22.24)**	**2.78**	**(10.94)**	**(5.42)**	**(2.41)**	**(6.21)**	**(6.16)**	**(55.43)**
40	**Return on Rate Base (%)**	**(28.02)**		**(30.15)**	**(44.59)**	**39.07**	**(87.95)**	**17.08**	**(37.67)**	**(53.34)**	**(15.82)**	**(62.29)**	**(58.28)**	**(7.74)**

Note

(I) Return on Rate Base is Present Rates Revenue plus Miscellaneous Revenues less Total Expenses expressed as a percentage of Rate Base.

APPENDIX 7F

COST OF SERVICE STUDY

SUMMARY FORECAST 2008

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E Ispat	Street Lighting
	OPERATING EXPENSES:	$		$	$		$	$	$	$		$	$	$
1	Bulk Power & Generation	1,577,290,862	AET & ET	459,983,132	195,116,447	51,671,201	132,021,792	207,030,613	70,000,286	128,850,955	40,260,239	40,024,545	247,342,455	4,989,196
2	Transmission	8,680,594	AET & ET	2,571,246	1,122,303	329,939	712,197	1,132,215	367,463	674,413	219,469	206,224	1,316,166	28,959
3	Distribution	116,189,137	AED & DCL	55,699,317	18,551,700	5,097,368	11,236,694	17,909,614	5,938,810	78,367	26,441	23,693	150,000	1,477,133
4	Administrative & General	110,343,215	SAW	75,488,279	12,620,646	3,753,533	3,989,428	7,210,796	2,131,432	295,339	99,649	89,290	565,300	4,099,520
5	Customer Accounts & Services	45,669,379	CAS	39,301,380	5,615,225	74,778	501,936	130,062	2,729	10,101	4,420	631	631	27,485
6	Total Operating Expenses	1,858,173,187		633,043,355	233,026,322	60,926,819	148,462,048	233,413,301	78,440,720	129,909,175	40,610,219	40,344,382	249,374,552	10,622,293
	DEPRECIATION EXPENSES:													
7	Generation	866,523	AET	256,670	112,032	32,935	71,094	113,021	36,681	67,322	21,908	20,586	131,384	2,891
8	Transmission	22,708,273	AET	6,726,332	2,935,925	863,113	1,863,095	2,961,853	961,276	1,764,253	574,128	539,477	3,443,066	75,756
9	Distribution	58,432,263	AED, DCL, SP & MET	33,109,432	7,938,031	1,638,785	4,259,955	6,335,437	2,105,894	4,840	2,117	302	302	3,037,166
10	Administrative & General	7,325,249	SAW	5,011,368	837,835	249,182	264,842	478,696	141,497	19,606	6,615	5,928	37,528	272,151
11	Total Depreciation Expenses	89,332,308		45,103,801	11,823,823	2,784,016	6,458,986	9,889,007	3,245,349	1,856,021	604,769	566,293	3,612,280	3,387,964
	TAXES AND OTHER DUTIES:													
12	Generation	438,178		129,791	56,652	16,655	35,950	57,152	18,549	34,043	11,078	10,410	66,437	1,462
13	Transmission	0		0	0	0	0	0	0	0	0	0	0	0
14	Distribution	10,418,825	AED, DCL & SP	7,127,753	1,191,666	354,416	376,690	680,858	201,254	27,886	9,409	8,431	53,377	387,085
15	Administrative & General	2,327,880	SAW	1,592,555	266,254	79,187	84,164	152,124	44,966	6,231	2,102	1,884	11,926	86,486
16	Total Taxes & Other Duties	13,184,883		8,850,099	1,514,572	450,258	496,804	890,134	264,769	68,160	22,590	20,724	131,740	475,033
	COST OF PROVIDING ADEQUATE MAINTENANCE & INTEREST PAYMENT ON BORROWINGS :													
	(i) Maintenance Expenses:													
17	Generation	3,149,012	AET	932,757	407,132	119,690	258,360	410,727	133,302	244,653	79,616	74,811	477,458	10,505
18	Transmission	5,108,113	AET	1,513,055	660,422	194,153	419,094	666,254	216,234	396,860	129,147	121,353	774,501	17,041
19	Distribution	63,329,696	AED, DCL, SP & MET	35,158,795	7,610,289	1,452,557	3,631,180	5,545,272	1,852,977	1,456	637	91	91	8,076,351
20	(ii) Interest Expenses	138,000,000	RATE BASE ALLOCATOR	71,614,949	15,773,217	7,455,388	7,504,930	14,331,904	4,252,950	3,672,722	1,203,000	1,122,127	7,007,829	4,060,985
21	(iii) Loss / (Gain) on Exchange	0	RATE BASE ALLOCATOR	0	0	0	0	0	0	0	0	0	0	0
22	**Total Maintenance & Interest**	209,586,821		109,219,556	24,451,059	9,221,788	11,813,564	20,954,158	6,455,464	4,315,690	1,412,399	1,318,381	8,259,879	12,164,881
23	**TOTAL EXPENSES**	**2,170,277,199**		**796,216,811**	**270,815,776**	**73,382,881**	**167,231,401**	**265,146,599**	**88,406,301**	**136,149,047**	**42,649,977**	**42,249,781**	**261,378,452**	**26,650,171**

SUMMARY FORECAST 2008

Line No.	Description	Total Company	Bases of Allocation	Residential Rate A	Commercial Rate B	Commercial Rate B 1	Large Load Rate D1	Large Load Rate D2	Large Load Rate D3	Large Load Rate D4	Large Load Rate D5	Large Load Rate E 1	Large Load Rate E Ispat	Street Lighting
	PERCENTAGE RETURN ON RATE BASE:													
24	Rate Base	2,536,328,354		1,316,224,827	289,898,963	137,023,998	137,934,545	263,408,796	78,165,780	67,501,650	22,110,158	20,623,789	128,798,236	74,637,610
25	Return at 7.5%	190,224,627		98,716,862	21,742,422	10,276,800	10,345,091	19,755,660	5,862,433	5,062,624	1,658,262	1,546,784	9,659,868	5,597,821
26	**TOTAL COST OF SERVICE**	**2,360,501,826**		**894,933,673**	**292,558,198**	**83,659,681**	**177,576,492**	**284,902,259**	**94,268,734**	**141,211,671**	**44,308,239**	**43,796,565**	**271,038,320**	**32,247,992**
	REVENUE REQUIREMENTS :													
27	Total Cost of Service	2,360,501,826		894,933,673	292,558,198	83,659,681	177,576,492	284,902,259	94,268,734	141,211,671	44,308,239	43,796,565	271,038,320	32,247,992
28	Less : Miscellaneous Revenues	155,752,693		59,363,546	17,805,664	9,685,720	10,124,997	21,243,606	5,767,868	8,905,775	2,747,639	2,705,898	16,242,804	1,159,174
29	**Revenue required from Sales(with 7.5% Rate Base)**	**2,204,749,133**		**835,570,127**	**274,752,534**	**73,973,961**	**167,451,495**	**263,658,653**	**88,500,866**	**132,305,896**	**41,560,600**	**41,090,667**	**254,795,516**	**31,088,818**
30	Present Rates Revenue	1,362,692,170		371,503,803	132,754,987	123,777,087	40,159,283	288,485,900	54,511,018	96,629,760	35,911,555	26,977,582	171,676,066	20,305,129
31	**REVENUE SURPLUS / (DEFICIENCY)**	**(842,056,963)**		**(464,066,324)**	**(141,997,547)**	**49,803,126**	**(127,292,212)**	**24,827,247**	**(33,989,848)**	**(35,676,136)**	**(5,649,045)**	**(14,113,085)**	**(83,119,450)**	**(10,783,689)**
32	**PERCENT SURPLUS / (DEFICIENCY) %**	**(61.79)**		**(124.92)**	**(106.96)**	**40.24**	**(316.97)**	**8.61**	**(62.35)**	**(36.92)**	**(15.73)**	**(52.31)**	**(48.42)**	**(53.11)**
33	Number of Customers	370,665		334,026	33,796	1,679	499	224	10	16	7	1	1	406
34	Present Avg Mthly Bill / Customer($)	N/A		92.68	327.34	6,143.39	6,706.63	107,323.62	454,258.48	503,280.00	427,518.51	2,248,131.83	14,306,338.83	4,167.72
35	Deficiency per Bill per Customer ($)	N/A		**(115.78)**	**(350.13)**	**2,471.86**	(21,257.88)	9,236.33	(283,248.73)	(185,813.21)	(67,250.53)	(1,176,090.39)	(6,926,620.81)	(2,213.40)
36	kWh Sold	6,960,000,000		1,862,000,000	754,468,000	163,212,000	563,250,000	866,070,000	310,000,000	694,000,000	205,000,000	220,000,000	1,303,000,000	19,000,000
37	Present Revenue per kWh (c)	19.58		19.95	17.60	75.84	7.13	33.31	17.58	13.92	17.52	12.26	13.18	106.87
38	Computed Cost per kWh (c)	31.68		44.87	36.42	45.32	29.73	30.44	28.55	19.06	20.27	18.68	19.55	163.63
39	**Gain / (Loss) per kWh Sold (c)**	**(12.10)**		**(24.92)**	**(18.82)**	**30.52**	**(22.60)**	**2.87**	**(10.97)**	**(5.14)**	**(2.75)**	**(6.42)**	**(6.37)**	**(56.76)**
40	**Return on Rate Base (%)**	**(25.70)**		**(27.76)**	**(41.48)**	**43.85**	**(84.78)**	**16.93**	**(35.98)**	**(45.35)**	**(18.05)**	**(60.93)**	**(57.03)**	**(6.95)**

Note

(I) Return on Rate Base is Present Rates Revenue plus Miscellaneous Revenues less Total Expenses expressed as a percentage of Rate Base.

SUMMARY OF BASES OF ALLOCATION

C1	Allocated per total distribution gross plant to component excluding specific assignment.
C2	Allocated per components of Substation and Customer Transformers in Distribution Electric Plant in:
C3	Computed depreciation allocated to component as per C1.
C	100% Customer component.
D	100% Demand component.
E	100% Energy component.
F	Interest and Finance charges. Not classified.
O	100% Other Cost component
D/C	50% Demand, 50% Customer components.
S	Specific Assignment.
C4	Allocation of Generation Materials and Supplies plus Fuel Stores to Demand.
C5	Allocation of Transmission Materials and supplies to Demand plus 40% of Communication Stores.
C6	Distribution Stores allocated to D,C and S on gross distribution investment excluding meters, plus 60% of Communication Stores. Meter Stores then added to Specific.
AET	Average and Excess Demand Transmission Level Allocator.
AED	Average and Excess Demand Distribution Level Allocator
ET	Energy Allocator Transmission Level
DCL	Distribution Customers by Level Allocator
SAW	Salaries and Wages Allocator
CAS	Customer Accounts and Services Allocator
MET	Meter Investment and Expenses Allocator
CWC	Cash Working Capital Allocator
SP	Specific Assignments e.g Expenses related to Street Lighting.

APPENDIX 8A

FORECAST OF ANNUAL FUEL PRICE AND FUEL COST

Method:

Projecting expected fuel cost over the period of interest involves executing the following steps:

1. For year 1 of the study, all existing plant as well as all new plant additions scheduled for this year if any, are considered for the analysis.

2. Next, the capacity factor, heat rate and energy production of each plant are used to simulate the operation of the generation system over the entire year to supply the forecast net energy generated. In general, the most efficient plant (lowest heat rates) will have the highest capacity factors. T&TEC's current practice is to project capacity factors and heat rates based on the most recent operational experience with suppliers, while the forecast of net generated energy is prepared annually as part of the Commission's 10-year sales forecast.

   A number of additional factors must also be taken into account during this exercise including planned maintenance and forced outage rates of individual generating units; availability of transmission plant; and in the special case of PowerGen's combined cycle plant at Penal power station, the availability of adequate supplies of fresh water for cooling. The objective of the exercise is to minimize total production cost of the system by applying the principles of economic dispatch. The key output of this step is the total consumption of each type of fuel.

3. The total cost of each fuel type in the year is then calculated.

4. The analysis then proceeds to the next year of the study period when any new plant scheduled for commissioning in that year will also be included in the analysis. The calculations then restart at step 2.

5. This process is repeated until calculations for the last year of the study period are completed.

At present this process is executed manually but the Commission intends to procure production simulation software in the future that will be able to model the system more precisely and yield more accurate results.

Results:

The forecasts of fuel price, total fuel cost, fuel cost per net unit generated, average fuel cost and projected fuel adjustment charge for the period 2004 to 2008 are given in the tables below.

Table 1: Forecast Fuel Prices for the period 2004 to 2008

Year	Gas Fuel Price USD/MMBTU	Gas Fuel Price TTD/MMBTU	Diesel Fuel Price TTD/l
2004	0.8390	5.2857	1.50
2005	0.8726	5.4974	1.50
2006	0.9075	5.7173	1.50
2007	0.9438	5.9459	1.50
2008	0.9816	6.1841	1.50

Table 2: Forecast Fuel Cost for the Period 2004 to 2008

Year	Diesel TT$'000	Gas TT$'000	Total TT$'000
2004	4,424	463,238	467,662
2005	5,752	503,573	509,325
2006	33,182	537,377	570,559
2007	0	562,708	562,708
2008	0	598,375	598,375

Table 3: Forecast Fuel Cost per Net Unit Generated for the Period 2004 to 2008

Year	Diesel TT¢/kWh	Gas TT¢/kWh	Total TT¢/kWh
2004	36.9	7.0	7.0
2005	36.9	7.2	7.3
2006	36.9	7.5	7.9
2007	0.0	7.6	7.6
2008	0.0	8.4	7.9

Table 4: Forecast of Average Fuel Cost and Fuel Adjustment Charge

Year	Average Cost ¢/MMBTU	Fuel Adj. ¢ / kwh
2004	533.0	0.0000
2005	555.2	0.3419
2006	601.8	1.0595
2007	594.6	0.9486
2008	618.4	1.3152

Inputs:

T&TEC's Capacity Requirements

A recent assessment of T&TEC's generation requirements indicates that new capacity must be added to the system as shown in the following schedule:

Table 5: T&TEC's Short-Term Generation Requirements

Year	Capacity Increment (MW)	Plant Type	Fuel Type	Possible Site
2005	60	Diesel	Diesel/Natural Gas	Tobago
2006	150	GT		
2007			Natural Gas	Unknown
2008	50	GT		
Total	260			

GT – Simple cycle gas turbine

The lead-time between issuance of a Request for Proposals (RFP) and plant commissioning, limits T&TEC's options as regards site selection and the technical specification of the plant. As a consequence, T&TEC is obliged to meet its capacity requirements in the short-term by supplementing the first two of these capacity increments with an increase in contract capacity from the Power Generation Company of Trinidad and Tobago (PowerGen). In the study referred to above, this increase was assumed to be 50MW covering the period 2004 to 2006, although for the purposes of cost estimating, the contracted capacity is increased to 75MW during 2006. This additional capacity caters for (1) load forecast uncertainty in the event that the demand exceeds projections and (2) capacity short-falls that may occur in 2006 prior to the commissioning of the new plant. The earliest commissioning date of the plant is the fourth quarter 2006.

For the purposes of this application, all capacity increments are evaluated as capacity contracts similar to those that currently exist with PowerGen and Inncogen. The capacity addition in 2005 is assumed to take place in Tobago in the fourth quarter since the installed capacity there must be increased in the near future. No specific site has as yet been identified for locating the capacity additions expected over the period 2006 to 2008, but these will certainly take place in Trinidad.

The capacity additions indicated above produce little improvement in system generation efficiency over the review period since the generation mix remains essentially unchanged. Continuing efficiency analysis and production simulation studies will establish whether or not a change to the existing plant mix is justifiable based on the expected cost of fuel and the relatively higher capital cost of more efficient plant types.

Fuel Prices and Escalation Rates

The 2003 price charged by the National Gas Company (NGC) for natural gas is US$0.8067/MMBTU. In calculating the natural gas price for subsequent years, the price of the previous year is increased by the escalation factor and then rounded to four decimal places. This procedure has continued from T&TEC's previous contract with NGC that expired in 1994. The annual escalation rate at present is 4.0% and this figure is maintained over the review period.

The 2003 diesel fuel price used in the analysis is TT$1.50/l which was held constant over the review period.

Exchange Rate

A fixed exchange rate of TT$6.30 to the United States Dollar was used throughout the analysis.

Units Sent Out Forecast

The forecast of units sent out (i.e. units purchased from power producers plus net generation by T&TEC) is obtained from T&TEC's *2004 Energy Sales and Peak Demand Forecast*.

APPENDIX 8B

Forecast of Energy Purchases from Power Suppliers

Table 1 contains the forecast energy purchases from power suppliers for the review period 2004 to 2008. These data were extracted from the MS Excel® spreadsheet entitled *Forecast of Fuel Price and Fuel Cost,* the source document used in the preparation of the MS Word® document of the same name.

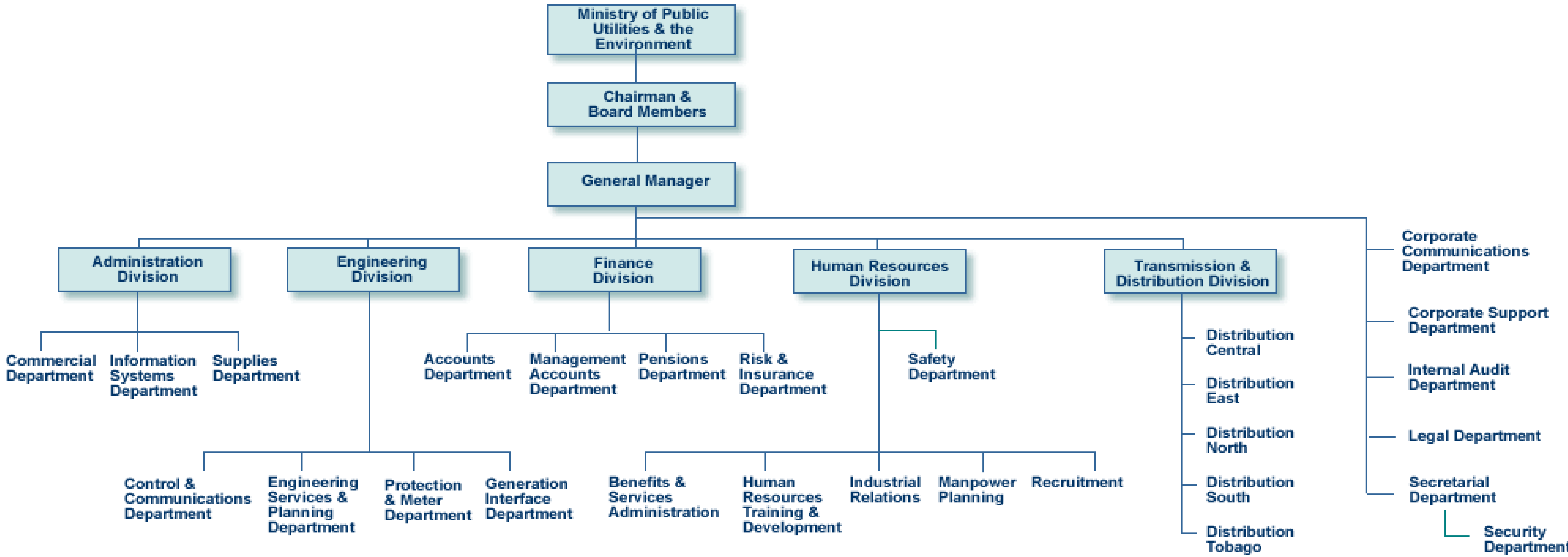
These data should be used for calculating the conversion costs (energy costs) of kWh purchased from suppliers.

Table 1: Forecast Energy Purchases from Suppliers for the Period 2004 to 2008

Year	Units Sent Out GWh	New Tobago GWh	Inncogen GWh	New Plant GWh	PowerGen GWh
2004	6,512	10	1,456	0	5,046
2005	6,782	29	1,564	131	5,058
2006	7,060	29	1,564	558	4,909
2007	7,290	216	1,564	854	4,656
2008	7,545	217	1,568	1,383	4,377

APPENDIX 9

ORGANIZATIONAL STRUCTURE



*

*

* Reports to the GM for administrative purposes only

APPENDIX 10A

COLLECTION POLICY

With regard to policies and procedures for dealing with customers in default of payment, the following is the observed practice within the Commission:

- If the bill is not paid within 14 days from the bill date, the customer becomes liable for disconnection.

- If disconnected, and payment is not made within 30 days, the meter will be removed.

- If two months following the removal of the meter the account remains unpaid, the account is 'final billed' (i.e. The final bill is sent to the customer requesting payment).

- If there is no response, the account is officially closed and the following approaches are implemented to collect outstanding monies: -
  - Investigations are done to determine whether another account exists in the customer's name. Where this is so, the customer is written and informed of our intention to transfer the outstanding balance to the account. In the case of no response the balance is transferred to the existing account, which can be disconnected.
  - Where no other account exists, efforts are made to contact the customer by phone and mail at an alternate address e.g. workplace. If this fails, the account may be referred to the Commission's contracted debt collectors for recovery. Alternatively, the Commission may initiate legal action through its attorney to recover the outstanding debt.

Regarding the range and accessibility of payment methods to customers, the following pertains:

- Customers of the Commission can pay their bills at any one of the Commissions fourteen (14) Service Centres.

- Additionally, customers can make payments at any branch of Republic Bank Limited, RBTT, First Citizen Bank, Scotia Bank, the Intercommercial Bank Limited and twenty six (26) selected TTPost payment centers located throughout the country.

Customers can make payments to their accounts using any of the following media:

- Cash
- Cheques
- Credit Cards
- Debit Cards, and
- Money and/or Postal Orders

N.B. Payments at TTPost and the use of the Credit Card are limited to Residential and Commercial accounts only.

APPENDIX 10B

PROCEDURE FOR THE WRITE-OFF OF BAD DEBTS

BACKGROUND

The Budget and Finance Committee, a Sub-Committee of the Board of the Commission, mandated that the write-off of bad debts should be done in compliance with statutory requirements i.e. after a period of four (4) years with no movement. This mandate was given in 1997. Prior to this, it was the practice to write-off closed account balances that were over two (2) years old.

PROCEDURE

Accounts Closed Four Years and Over

Before a request is submitted for the write-off of bad debts, it is necessary for Management to provide assurances that the loss to the Commission is kept to the absolute minimum. The following initiatives are employed to limit the Commission's exposure to bad debts:

- reduction on the time taken to final bill an account and thereby initiate recovery as a closed account
- closer monitoring of the performance of the contracted debt collector
- initiating the prompt disconnection of delinquent accounts
- increasing the use of litigation particularly for industrial accounts
- closer monitoring of street-lighting accounts

Listings of accounts, which have been closed four (4) years and over, are produced by the Information Systems Department. These listings are produced after any such balances in the names of customers with active accounts are transferred to these accounts.

Separate listings are produced for Domestic and General, Industrial and Street Lighting accounts.

Specific Write-Offs

Balances on accounts, which have been closed less than four (4) years, may also be considered for write-off in the following circumstances:

- customer's inability to pay

- inability to locate the customer

- where a business has gone into liquidation and the receiver/liquidator has clearly repudiated the Commission's unsecured debt

A listing of accounts for specific write-off is prepared and documentation supporting the recommendation for write-off must be produced.

ACCOUNTING PROCEDURE

In keeping with prudent accounting policy, a recommendation should be made annually to write-off long outstanding balances. Each accounting year the Commission makes a provision for bad and doubtful debts based on set formulae in relation to the expectation that only certain proportions of each class of customer will settle their bills in full. When an actual write-off is recommended and approved by the Board of the Commission, the total amount to be written-off is applied against the accumulated provision, thereby transferring the provision to specific debts. Once this is done, the provision is again reviewed and adjusted based on the required formulae.

APPENDIX 11

PRELIMINARY FORECAST OF T&TEC'S CONTRACT CAPACITY INCREASES: 2004 TO 2008

Introduction

The results of a recent preliminary planning study indicate that T&TEC's generating capacity must be increased in the short term in order to supply increasing system demand while maintaining acceptable levels of reliability. The results and conclusions of the study are the subject of this paper.

Forecast Peak Demand

By 2008, system peak demand is expected to reach 1,152MW, an increase of more than 200MW over the 2002 peak of 930MW[†]. The forecast over the review period to 2008 is given in Table 1.

Table 1: Base Forecast of System Peak Demand

Year	Forecast System Peak Demand (MW)
2004	1,013
2005	1,064
2006	1,105
2007	1,129
2008	1,152

Alternative Cases

An increase in the contracted capacity from PowerGen is considered initially since this is the only option available to T&TEC for meeting its capacity requirements in the short term. A 50MW capacity increase covering the period 2004 to 2006 is considered. In addition to this, the contracted capacity from Trinity Power will increase from 195MW to 210MW by 2005 in keeping with the contract between T&TEC and its supplier.

† This growth in demand may be compared to that experienced over the period 1994 to 2002. By the end of 1994 when PowerGen was formed, the system peak demand stood at 607MW. By 1999 when the Trinity Power power plant was commissioned, peak demand had reached 815MW, increasing to 930MW by 2002.

Due to the lead time required for installation of new plant, the first new plant addition to the system is considered to take place in the fourth quarter of 2005. This is assumed to be in Tobago since the capacity on the island must be increased to satisfy T&TEC's planning criteria for Tobago. A maximum plant capacity of 60MW is assumed which would both meet Tobago's requirements as well as supply north-east Trinidad. A unit size of 15MW is also assumed.

It is expected that the plant will be capable of operating on both natural gas (main fuel) and diesel (back-up fuel). Provision of a natural gas supply by the end of 2006 is assumed. The earliest unit addition in Trinidad is assumed to take place by the fourth quarter of 2006. Three unit sizes are considered viz. 50MW, 75MW and 100MW.

Results

The results of the analysis are summarized in Table 2 below. Cases A50, A75 and A100 consider 50MW, 75MW and 100MW unit additions respectively.

Table 2: Contracted Capacity Increases for Various Cases

Year	Case A50 50MW Units	Case A75 75MW Units	Case A100 100MW Units
2004			
2005	4 x 15	4 x 15	4 x 15
2006	3 x 50	2 x 75	2 x 100
2007			
2008	1 x 50	1 x 75	
Total	260MW	285MW	260MW

The results show that for ***Cases A50*** and ***A100***, 260MW of capacity are required (in addition to the PowerGen and Trinity Power increases) over the review period. This is lower than in ***Case A75*** where 75MW units are considered. For the purposes of budgeting for contracted capacity payments to suppliers, the results of Case A75 will be used since this will result in a slightly higher generation cost.

It should also be noted that the study highlights that there is significant risk of capacity shortfalls until 2006, prior to commissioning of new plant in the fourth quarter. This may result in T&TEC exceeding the contracted capacity limit with PowerGen, so that a further capacity purchase *may* be needed in 2006. The cost of this additional capacity must be taken into account and for the purposes of budgeting, this further capacity increment is taken to be 25MW.

Conclusion

Based on the above results, we conclude that for the purposes of the Commission's application to the RIC, T&TEC must increase its contracted capacity over the review period as follows:

- PowerGen: 50MW increase from 2004 to 2005 inclusive, increasing to 75MW for the period Q1 to Q3 2006
- Trinity Power: 15MW increase from Q3 2004 to beyond 2008
- Tobago: 60MW increase from 2005 Q4 to beyond 2008
- Trinidad: 150MW increase in 2006 Q4 to beyond 2008
  75MW increase in 2008 Q4

APPENDIX 12A

MAINTAINING THE SUPPLY / DEMAND BALANCE

AT THE GENERATION AND TRANSMISSION LEVEL

1.1 Maintaining the Supply/Demand Balance

1.1.1 Generation and Transmission

Maintaining the balance between supply and demand is achieved by appropriate planning of the power system at the generation, transmission and distribution levels. This planning must take place well in advance of the date at which supply is needed, to cater for the lead time from recommendation to commercial operation. The intervening steps are in general lengthy, and include approval of recommendations; detailed design; budgeting; tendering for supply of equipment and services; tender assessment; contract negotiation; manufacture and shipping; construction and commissioning. For generation and transmission projects, the minimum lead-time could be three to four years inclusive of the time required for study and preparation of recommendations. For large distribution projects where the majority of materials and equipment are held as stock items a lead time of twelve to eighteen months would be appropriate, while small projects could be executed in under a year contingent on sufficient resources being available.

The need to determine system requirements well in advance of the in-service date consequently imposes the additional need for forecasts of demand over the planning period. Thus, every planning activity starts with the preparation of an appropriate forecast. The planning horizon is determined based on the objectives of the study and the useful life of the plant to be installed. In general, generating and transmission plant have useful lives of at least thirty to forty years although economic life may be somewhat shorter if the reliability, financing costs and efficiency improvements of new plant make them more attractive than the on-going operations and maintenance costs of older equipment.

In long term planning studies, T&TEC uses a 20-year planning horizon. This is considered adequate since the period covers a significant portion of the equipment useful life; it leads to the forging of a long term development trajectory or context into which early plant additions can be placed; it facilitates optimization of the development plan by taking into account present and future capital, operations, maintenance and other costs.

For generation studies, a global forecast of net units generated and purchased is required. This is obtained from the Commission's annual 10-year *Energy Sales and Peak Demand Forecast*, which is extended as required to cover the planning period. Forecasts for transmission studies consist of projections of individual substation demands, which are based on trending of actual load measurements.

Analytical tools and methods are employed to model and assess the systems and their performance. For generating studies the Generating System Capacity Expansion Planning (GSCEP) software package is used. This was developed and tested by in-house engineering staff in 1991 and is maintained up to the present time[1]. The Loss of Load Expectation (LOLE) method is used in assessing the adequacy of the generation system.

For transmission planning studies, the EDSA power systems analysis software is used. This is a commercially available suit of programmes for conducting loadflow, short circuit and stability analysis on electric power systems.

For both generation and transmission studies, the Commission's standard planning criteria are used to assess system performance and to identify deficiencies. Typically, the analysis of the generation or transmission system commences with the first year of the study period. The initial system is analyzed and its performance compared against the established planning criteria. Where no deficiencies are detected, the analysis proceeds to the next study year. When however a shortcoming is identified, a traditional problem solving approach is adopted in which alternatives for addressing the deficiencies are advanced and each alternative is analysed to assess its impact on system performance. Judgement is used in pruning the tree of possible alternatives so that obvious non-contenders are eliminated early in the process. In this way only realistic alternatives are carried forward to the next study year of the planning period and the analysis is continued. This process is repeated until the end of the study period is reached.

At the end of this process several alternative schedules of system reinforcement or expansion would have been prepared, each of which enables the system to meet the projected demands over the planning period while satisfying all design criteria. These schedules would typically consist of specific works to be carried out in certain time frames. By this means therefore, the balance between supply and demand is maintained.

The costs and benefits of each alternative are evaluated after which they are ranked in order of decreasing net benefit. This often reduces to a ranking by increasing total cost since the total benefit of each alternative (system delivery capability or total revenue from service delivered by the upgraded system) is usually the same. Finally, subjective issues are considered and the final recommendation made.

[1] T&TEC however plans to purchase a commercially available package with wider capabilities that would reduce the demand on in-house staff for programme development and maintenance.

APPENDIX 12B

MAINTAINING THE SUPPLY / DEMAND BALANCE AT THE DISTRIBUTION LEVEL

At the distribution level, the supply/demand balance for electricity service offered to our customers entails monitoring of the existing system, planning and design of infrastructure upgrades/expansions and a structured maintenance program.

MONITORING

At the distribution level the existing network is monitored on a regular basis by the Commission to identify changes in the system performance. Feeder loads, substation bus and supply voltages and the physical condition of all equipment are monitored. System performance records together with trends in Residential, Commercial and Industrial development are assessed and used as planning inputs towards future system development plans. The Commission also interfaces on a continual basis with Governmental Agencies such as the National Housing Authority and private residential and industrial contracting companies. The information gathered is used to ascertain future load growth, the need for feeder expansion, substation expansion/construction and transmission line upgrade.

PLANNING

Lead-time for distribution system reinforcement projects at 12kV is approximately six months to a year. The time frame allows for analysis of the data, planning and design, ordering of material, tendering for labour (as required), construction and commissioning of the plant.

New requests for electricity supply from residential, commercial and industrial customers are assessed on an individual basis. Having documented the request, the supply requirements of the installation are quantified. In the case where a supply at the requested voltage exists, load and voltage checks are done on the circuits and an assessment is made on infrastructure requirements. Where additional infrastructure is required, investigations are undertaken, infrastructure designs are done and the projects planned for construction along with the relevant administrative documentation.

MAINTAINING THE SUPPLY

The Commission also ensures that the supply demand balance is met by implementing a comprehensive programme of preventative maintenance. To aid in this respect, the Commission maintains detailed records and databases of all equipment. All work done on each item of plant is recorded and used in identifying its historical performance. Trends of repeated failures are identified and corrective action taken to ensure the quality of supply objectives and minimize interruptions to customers.

APPENDIX 13

RELIABILITY CENTRED MAINTENANCE

Reliability Centred Maintenance (RCM) is the process used to determine the maintenance requirements of any physical asset in its operating context. The starting point for the process is an analysis of the functions of the equipment (based upon functional requirements and performance standards), potential functional failures, failure modes and effects (consequences of the failure) and their criticality.

The RCM process entails asking seven questions about the asset or system under review:

1. *What are the functions and associated performance standards of the asset in its present operating context?*
2. *In what ways can it fail to fulfill its functions?*
3. *What causes each functional failure?*
4. *What happens when each failure occurs?*
5. *In what ways does each failure matter?*
6. *What can be done to predict or prevent each failure?*
7. *What should be done if a suitable proactive task cannot be found?*

The fifth of the seven questions asks how does each failure matter, since it is a basic tenet of RCM that what we are trying to avoid is the consequences of each failure, much rather than the failure itself. For any task to be worth doing, it must be able to deal successfully with the consequences of failure. In RCM, the failure consequences are:

- Hidden failures: functional failures which will not be evident in normal circumstances, and usually concern protective devices which are not fail-safe.
- ***Safety or environmental:*** failures could hurt or kill someone, or lead to the breach of an environmental standard.
- ***Operational***: where the functional failure will have some adverse effect on operational capability.
- ***Non-operational***: where the only cost is the cost of repair.

The sixth and seventh questions ask what can be done to predict or prevent failure, or if not, what can then be done. RCM provides strict criteria for assessing if a task is 'technically feasible' in addressing the failure mode. The pro-active and default tasks (in order of preference) are:

- *On-condition tasks, where items are checked (or inspected) and left in service if they are performing satisfactorily.*
  For on-condition tasks to be technically feasible, the failure characteristics need to satisfy the following requirements:

  The frequency of an on-condition task is governed by the "P-F interval", which is the period from when impeding failure can be detected to when the failure would occur if nothing were done to prevent it. An on-condition task must be carried out at intervals, which are less than the P-F interval if it is to have a reasonable probability of detecting a failure in the processes of occurring. RCM debunks the long held belief by some maintenance professionals that the frequency of condition monitoring is based on the criticality of failure. It is how long something takes to fail that will ultimately determine how often condition monitor should be carried out.

- *Scheduled Restoration and Discard Tasks, where items are either overhauled or replaced at a specified frequency regardless of their condition.*

  For scheduled restoration and discard tasks to be technically feasible, the failure modes must have the following characteristics:

  The frequency of schedule restoration and discard task is governed by the 'useful life' of the item, the age at which the conditional probability of failure increases rapidly. (This is that age after which most failures are likely to occur.)

- *Failure Finding Tasks, where hidden functions are checked to determine if they are still working.*
  The frequency of a failure-finding task is determined by the reliability of the hidden function expressed as the mean time between failure (MTBF) and the availability that is required from it (which is in turn determined by the risk of multiple failure.)

- *No Scheduled Maintenance, where no action is taken to prevent failure.*
  "No scheduled maintenance" is often referred to as 'run to failure' and is the outcome of an RCM analysis if no task can be found which is either technically feasible (meaning the task is technically not preventable) or worth doing.

- *Redesign, where items or processes are redesigned*.
  Redesign of the asset or some processes associated with its operation or maintenance will be the outcome if no task can be found which is both technically feasible and worth doing, and the consequences of allowing the failure to occur (either from a risk or economic perspective) are unacceptable or undesirable.

Only those tasks which are both technically feasible and worth doing are selected. This ensures that tasks that will have no or little effect in reducing failure rates or are of no benefit will be eliminated from scheduled maintenance routines.

The application of RCM logic will reveal that for some failure types there is no form of effective preventive or predictive maintenance. This conclusion is based purely on the technical characteristics of the failures themselves, and not their consequences. These types of failures will give little or no warning they are about to happen, and can occur at any time (i.e. they are not age related). The most effective way of managing them is to manage the failure consequences rather than the failure itself, such as by providing protective devices or system redundancy.

The process of analysing functions, functional failures, failure modes and criticality yields many opportunities for improving performance and safety. It prevents maintenance policies being implemented for failures that are effectively not preventable or predictable which could lead to a waste of maintenance resources on fruitless tasks.

APPENDIX 14

EFFICIENCY IMPROVEMENTS

The following efficiency improvements were introduced over the last (5) years.

TRANSMISSION AND DISTRIBUTION

Capacitor Placement Project

Low power factor is one of the leading causes of electrical systems inefficiencies. A variety of electrical systems problems can be resolved by the proper application of Power Factor corrective capacitors to correct lagging power factor. The key benefits are:

- Improved system capacity
- Reduced line losses
- Improved voltage levels
- Reduced infrastructure request/requirements

To achieve these benefits a total of 235 capacitor banks, with a total rating of 93,450 kVAr, were installed on 146 of the Commission's distribution feeders.

Other Service Improvements

Year	System Losses
2004	8.00%
2005	7.75%
2006	7.50%
2007	7.25%
2008	7.00%

Vehicle Fleet Upgrade

The vehicle replacement policy takes into consideration the following:

- Age of the fleet
- Preventative Maintenance Expenditure Level
- Downtime Cost
- Fuel Cost
- Rents versus Purchase
- Fuel Type - Diesel versus Gasoline

The study recommends:

- A replacement timing of eight (8) years for vehicles with hydraulic attachments (Borers, Buckets and Lift Trucks) and between four (4) to six (6) years for all other vehicles.
- Replacing vehicles via direct purchase as opposed to lease/rentals.
- Preference be given to diesel engines for all new additions to the fleet.
- Purchasing some of the rented vehicles at the end of the lease period.

In 1999 the fleet consisted of two hundred and ninety two (292) vehicles, 20% of which were hydraulic vehicles. Over the past five (5) years one hundred and forty two (142) new vehicles were purchased and the fleet reduced to two hundred and seventy four (274). Of the new vehicles, fifty-eight (58) were Aerial Lift Trucks and three (3) were Lift Trucks. This increased the percentage of hydraulic vehicles to 36% of overall fleet. The increased mechanization has empowered the crews in meeting targets with regards to customer response time.

It is to be noted that all new vehicles are diesel powered. This has seen a reduction in the annual fuel bill from $2.0M to $1.28M over the period.

The benefit of the change in fuel type is not quite apparent because of the increased number of crews due to crew size reduction and increased vehicle use due to shift systems.

The overall fleet operating cost, which consists of fuel, maintenance and rent has been reduced from $8.7M in 1999 to $4.8M in 2002.

Pole Replacement

A total of 29,000 rotted poles were changed on the distribution system between 1999 and 2003. This has greatly reduced the number of outages experienced by customers due to this cause and has greatly reduced the incidence of costly unplanned maintenance.

Establishing of Service Centres

Fourteen (14) service centres were established within Trinidad and Tobago. These have improved the Commission’s collecting ability by making available, easily accessible locations for customers to pay their bill.

Restructuring of Transmission & Distribution Division

The following changes were introduced to more effectively manage the Division’s resources thereby improving efficiency and the quality of service to customers.

Optimizing of Crews

The Commission has adopted the policy that the task to be undertaken must determine the skills and number of personnel required to safely complete the job.

As a result, crews have been reduced in most areas of operations. The greatest impact being in overhead lines crews. These crews are responsible for the maintenance and construction of the Transmission and Distribution overhead lines and have been reduced in size by over 50% in most cases. These changes have led to cost reductions and improvements in work methods.

Shift System for Small Crews and Cable Crews

Small Crews are the crews that are responsible for load checks, street lighting etc. on the distribution system. These crews have been placed on a two-shift system. This has resulted in the following.

- Improved efficiency in inspection and maintenance of defective streetlights.
- More efficient vehicle utilization.
- Greater flexibility in outage scheduling and work programming.
- Greater efficiency in responding to breakdown with reduced overtime cost.

Meter Sealing

In an effort to reduce non-technical losses on the Distribution System, the Commission undertook a meter sealing exercise. Over 99% of the Commission's meters are now sealed.

Automatic Meter Reading (AMR)

Accessing meters has been an on-going problem faced by the Commission. The resulting estimated billing, continues to have a negative impact on customer service. A number of initiatives e.g. reading meters outside normal working hours, has resulted in a significant reduction in unscheduled estimated billing. However, to improve efficiency and customer service, available technological options were reviewed and a pilot project using automatic meter reading was undertaken.

Benefits from the implementation of AMR are:

- Improved accuracy in reading meters
- Enhancement of the revenue collection programmes due to accurate billing of consumption on a timely basis.
- Improvement in the ability to detect meter tampering and energy theft.
- Improved cash flow and freed resources for utilisation in other productive area resulting from a reduction in estimated bills, billing complaints and queries.

FINANCE

Risk Management

Within the last five (5) years, greater emphasis has been placed on the management of risks, as opposed to insuring against these risks. This has resulted in:

- Lower insurance premiums than would have been obtained if there had been no risk management initiatives.
- Greater safety awareness and therefore fewer accidents, through risk surveys and the implementation of recommendations made by professional risk managers. This has resulted in a reduction in the time lost as a result of accidents.

PeopleSoft

- More flexible reporting capabilities.
- Decentralization of certain processes resulting in speedier processing of transactions.
- More timely and reliable financial information

PROTECTION AND METER

Electronic Meters

The acquisition of this equipment has:

- Reduce maintenance cost
- Improve billing accuracy

CONTROL AND COMMUNICATIONS

SCADA Equipment

The Supervisory, Control and Data Acquisition (SCADA) equipment has replaced the older and obsolete equipment thereby:

- Reducing maintenance cost
- Improving reliability
- Encouraging redeployment of staff into other areas.

COMMERCIAL

Banner

- Lower maintenance cost
- Provide online, real-time access to customer information
- Improve reporting capabilities
- Provide greater credit control
- Ability to generate duplicate bills for any period in the past
- Allows greater uniformity in transactions among the different Areas

HUMAN RESOURCES

There has been:

- Employee training at all levels both locally and internationally.
- Award incentive schemes for both the Areas and individuals.

INFORMATION SYSTEMS

Mainframe

There has been a move from the mainframe, which has resulted in the reduction on maintenance cost.

STAFF ACCIDENTS

Within the last five (5) years, the number of serious accidents has shown a steady decline as a result of improved health and safety practices as follows:

Year	No. of Accidents
1999	111
2000	99
2001	71
2002	35
2003	29

These relate to accidents affecting staff, contractors, members of the public and contractors' employees.

APPENDIX 15

PLANS TO IMPROVE OPERATING EFFICIENCY: 2004 TO 2008

Distribution Automation

Distribution automation is a way for using advance technology to increase the reliability of the distribution system at reduced operation cost. Automation applied to the distribution feeders can reduce the time required in fault location, reduce the need for crew to travel to remote switching points, and result in rapid restoration of power supplies to affected customers.

This will lead to significant improvements in reliability and cost savings.

System Reinforcement

In addition to its extensive preventative maintenance programme, T&TEC continually examines its Transmission and Distribution system and effect reinforcement when required to ensure that power is delivered reliably to its customers. The following substations are to be reinforced by the addition of distribution transformers to increase available capacity:

- Phillipine Substation
- Champs Fleurs Substation
- Diego Martin Substation
- Bamboo Substation
- St. Mary's Substation
- St. James Substation
- Tabaquite Substation
- Rio Claro Substation

Underground Residential/Commercial Development

The Commission recognises the many benefits to be derived from an underground distribution system and is moving towards residential/commercial underground development.

The benefits to be derived are:

- Improved visual amenity stemming from improved streetscape aesthetics, removal of poles and wires and reduction in the need to prune or cut trees.
- Improved safety to the public.
- Reduced motor vehicle accidents and damage to plant caused by collisions of vehicles with poles.

- Reduction in the maintenance cost.
- Improved reliability of supply as the system is not as exposed as overhead lines to tree, animals, cars etc.
- Reduced inconvenience to the public. No guy wires, poles etc on customers premises.
- Reduced revenue losses caused by electricity outages.
- Reduced tree trimming cost.

Geographic Information Systems (GIS)

Implementation of a system wide GIS representation of the electric network in a graphical database format will facilitate the following:

- Implementation of a Work Management System
- Outage Management
- Inventory Management
- Efficient power system modelling and design of the system

This can also be extended to fleet management and other areas.

Maintenance and Operations Management System

The operation of the distribution network and delivery of services, especially emergency services, require tools to determine the status of the network, its relationship with customers and the geography of the Area. The tools must enable operators to respond to the expectation of sophisticated customers.

In order to achieve this, the following systems are to be put in place:

- A map of the Transmission and Distribution system in digital form
- An outage management system
- A work and maintenance management system
- Integration between the customer information system, the communication system and the above systems.

It is anticipated that the implementation of Maintenance Operations Management System integrated with the Customer Information System, the Interactive Voice Response System and Digital Maps will result in the following benefits:

- Improved customer service response and satisfaction
- More timely information for Management Decision Making and reporting
- Better security for the Commission's fixed asset records especially its underground system.

APPENDIX 16A

PROPOSED PROJECT SCHEDULE 2004 - 2008 (over $1m)

TRANSMISSION

PROJECT DESCRIPTION	2004	2005	2006	2007	2008
	$M	$M	$M	$M	$M
Bamboo/Gateway 132kV UG Cable	20.0	30.0	10.0	0.0	0.0
Invaders Bay 33kV S/S	0.0	7.0	0.0	0.0	0.0
Gateway S/Station 132kV	26.0	21.0	3.0	0.0	0.0
Gateway S/Station 12kV	0.0	6.0	2.0	0.0	0.0
Gateway St. James 33kV	0.0	0.0	0.0	0.0	2.6
Gateway to Edward St - 33kV UG Circuit	0.0	0.0	4.0	0.0	0.0
Bamboo/Gateway 132kV Double Circuit Tower Line	12.5	10.0	0.0	0.0	0.0
Edward St. 33kV S/Station	12.0	0.0	0.0	0.0	0.0
San Juan 33kV S/Station	4.0	0.0	0.0	0.0	0.0
Replace 33kV OCB @ Abbatoir S/S	0.0	3.0	0.0	0.0	0.0
Establish System Earth @ Barataria S/S	0.0	0.0	2.5	0.0	0.0
POS/Gateway 33k Interconnectors	0.0	0.0	3.0	0.0	0.0
Toruba 66kV S/S	0.0	7.0	0.0	0.0	0.0
Upgrade South East Ring 33kV OH	0.0	0.0	20.0	0.0	0.0
Lowlands 33kV S/S	2.0	4.0	0.0	0.0	0.0
Relocate Champs Fleurs	4.5	0.0	0.0	0.0	0.0
Macoya 66kV S/Station	10.3	3.0	0.0	0.0	0.0
Pinto Rd. S/Station Upgrade	20.0	8.0	0.0	0.0	0.0
Mt. Hope S/Station Upgrade	14.0	11.0	0.0	0.0	0.0
Pinto Rd/San Rafael 132kV Double Circuit Tower Line	15.0	2.0	0.0	0.0	0.0
Tunapuna 66kV S/Station	15.0	0.0	0.0	0.0	0.0
Bamboo 132kV S/Station	8.6	0.0	0.0	0.0	0.0
Reinforce Trincity 66kV Ring OH	0.0	8.0	0.0	0.0	0.0
Trincity 66kV S/Station Upgrade	7.4	0.0	0.0	0.0	0.0
Unicell 66kV S/Station	7.2	0.0	0.0	0.0	0.0
O'Meara S/Station Upgrade	0.0	6.0	0.0	0.0	0.0
Five Rivers S/Station Upgrade	0.0	6.0	0.0	0.0	0.0
San Rafael 132kV S/Station	5.3	0.0	0.0	0.0	0.0
Bamboo/Mt Hope 132kV Double Circuit Tower Line	3.0	2.0	0.0	0.0	0.0
Longdenville S/S	8.3	0.0	0.0	0.0	0.0
66kV supply to Nitrogen 2000	5.3	0.0	0.0	0.0	0.0
Charlieville 66kV S/Station	2.0	0.0	7.0	0.0	0.0
Construct Penal/Harmony Hall 66kV	0.0	0.0	0.0	5.7	0.0
Construct Phillipine/Penal 66kV	0.0	0.0	0.0	3.3	0.0
Penal Substation 132/66kV Transformer	0.0	0.0	0.0	4.0	0.0
Establish Earth System for 33kV Tobago	0.0	0.0	1.5	0.0	0.0
Establish new Roxborough Substation	0.0	0.0	0.0	0.0	5.0
Construct 33kV OH supply to Roxborough SS	0.0	0.0	0.0	0.0	10.0
TOTAL	**202.4**	**134.0**	**53.0**	**13.0**	**17.6**

APPENDIX 16B

PROPOSED PROJECT SCHEDULE 2004 - 2008 (Over $1m)

DISTRIBUTION (ALL AREAS)

PROJECT DESCRIPTION	2004	2005	2006	2007	2008
	$M	$M	$M	$M	$M
Six (6) 66kV Fault Interruptors re:Westmoorings & Barataria S/S	1.0	1.0	0.0		
Replace 2 existing Reyrolle ORT OCBs with 2-800A Vacuum Units	2.5	0.0	0.0		
33kV ring to Santa Cruz S/S	8.1	0.0	0.0		
U/G Ext	3.3	1.3	1.3	2.7	3.0
U/G Network Switchgear & Fuse Gear	1.4	1.4	1.4	2.7	3.0
Pole Replacement Programme	16.0	16.0	16.0	16.0	16.0
Voltage Corrections	3.3	3.0	3.0		
11-Panel replacement for 12kV board	1.5	1.5	1.0		
2-33kV Circuit Breakers	1.0	1.0	0.0		
2-12/16mVa 33/12kV DY11 Transformers	4.8	2.4	0.0		
Replace aging 6.6kV Reyrolle switch-board with 5-panel vacuum 12kV switch-board	2.0	1.5	0.0		
Replace rad#1 cable with 185mm2 XLPE	3.0	0.0	0.0		
Construction of a new Northern Area Building	5.0	10.0	0.0		
Remote Data Acquisition(AMR)	22.0	32.0	32.0		
System Upgrade	1.5	1.5	0.2		
Removal of line from over the Carenage Hill to an accessible route along the Main Road	1.0	1.5	0.0		
Replace aged OH Line with higher capacity UG Cable	2.0	2.0	0.0		
Replace 6.6kV cable & Install 12kv cable	1.0	1.0	1.0		
Upgrade City 6.6kV UG Network	5.0	15.0	20.0		
Install 25 Pullboxes and Duct Work	1.0	1.0	1.0		
Replace 7-panel Yorkshire 12kV switch-board with 5-panel vacuum switch-board	0.0	0.0	1.5		
All Other OH Line Extensions	1.5	1.5	1.5		
Line Clearing for New Projects	1.0	1.0	1.0		
All other Extensions	3.0	3.0	3.0		
Connect new Customers RMU & Fusegear	1.4	1.4	1.4		
S/lgt @ Lady Young Rd & Prioroty Bus Route	4.0	0.0	0.0		
Purchase & install 12.5-16 mVA TFM	3.4	0.0	0.0		
HV/LV Line Extensions	2.0	1.0	1.0	8.4	9.0
Service Connections	1.5	1.5	1.5		
Preliminary Surveys & Investigations	2.5	2.5	2.5	5.5	6.0
O/H Line Transformers	4.8	4.8	4.8	7.0	7.0
Install Non T/F Type Meters	2.5	2.5	2.5	6.0	7.0
Install 7 panel 12kV board	0.0	1.2	0.0		
OH Line Extensions	7.0	4.5	4.5		
S/lighting @ South ByPass	3.0	4.0	0.0		
Renovations to Welfare Block	0.0	1.0	0.0		
One 12kV 7-panel switchboard	1.2	0.0	0.0		
Reconductoring of Fyzabad-Brighton	1.1	0.0	0.0		
Upgrade of Service Centre & Office Expansion	1.5	0.0	0.0		
Underground HV Extension between L'Anse Fourmi and Charlotteville	2.0	0.0	0.0		
Streetlighting upgrades	6.0	2.0	2.0	2.8	3.0
Distribution Automation	0.8	24.0	4.0	5.0	

APPENDIX 16B

PROPOSED PROJECT SCHEDULE 2004 - 2008 (Over $1m)

DISTRIBUTION (ALL AREAS)

PROJECT DESCRIPTION	2004	2005	2006	2007	2008
Replacement of 33kV VCB's	1.0	0.0	0.0		
Purchase & install 1-12.5/16mVa 66/12kV TFM,breaker & isolator,UG Cable	1.5	0.0	0.0		
Service Connections	1.0	0.8	0.8	5.5	6.0
New Office Building	1.5	2.5	0.0		
Reconstruct 12kV OH Line	1.0	0.0	0.0		
To relocate S/S	0.0	3.0	0.0		
Develop 2 - 12kV Feeders (UG)	1.5	0.5	0.0		
1 - 12kV board & relays	1.0	0.0	0.0		
Upgrade 2 TFMs from 12mVa to 20/25mVa	2.0	0.0	0.0		
Expansion of S/Station	2.7	0.0	0.0		
Establish 12kV Switching Station @ Millenium Compound	1.0	0.0	0.0		
12kV Cable Tie	1.5	0.0	0.0		
Caura/ Maracas 12kV line	1.0	0.0	0.0		
Inst TFM, Circuit Breakers, Switch house, auto reclosures	4.0	0.0	0.0		
HV/LV Ext	1.0	0.0	0.0		
System Reinforcement	5.2	0.0	0.0		
S/Lgt @ C/Roosevelt H/W & Priority Bus Route	6.0	6.0	0.0		
Battery Charger & batteries -14 stations	1.4	0.0	0.0		
Replacement of corroded cradles on insulator strings 132kV lines	1.5	0.0	0.0		
Install (1) 12kV vacuum board	2.7	1.0	0.0		
Install (1) 12mVa TFM	2.4	0.0	0.0		
Replace 2x6mVa tfms with 2x12mVa TFM	4.6	0.0	0.0		
Replace 1x3mVa tfms with 1x2mVa TFM	0.0	2.4	0.0		
Separation of B.C. Couva and Pt. Lisas, Chag E 66kV Line. Upgrade of Conductors.	1.5	0.0	0.0		
UG Cable Utility Corridor	1.0	0.0	0.0		
UG Cable Projects	1.2	0.0	0.0		
Upgrade of highway s/lighting. Restoration of U/G circuits	1.0	0.0	0.0		
Substations Upgrade	0.0	0.0	0.0	70.0	75.0
Overhead Line Upgrade	0.0	0.0	0.0	20.0	20.0
TOTAL	**186.7**	**165.1**	**108.7**	**151.6**	**155.0**

APPENDIX 16C

PROPOSED PROJECT SCHEDULE 2004 - 2008

PROTECTION AND METER

PROJECT DESCRIPTION	2004	2005	2006	2007	2008	REMARKS
	$M	$M	$M	$M	$M	
Replacement of electro-mechanical meters	1.0	-	-	-	-	Replacement of electro-mechanical meters
Replace Solkor protection relays	1.2	-	-	0.8	-	Replace Solkor protection relays on N/East, Tobago 33kV Ring
Substation Protective Monitoring and Control Upgrade	1.3	2.5	2.5	-	-	Substation Protective Monitoring and Control Upgrade
Test Van	-	2.0	-	-	-	Test Van
AMR for Industrial Meters	0.5	2.5	2.5	-	-	AMR for Industrial Meters
AMR for 3ph Commercial Customers	5.0	10.0	10.0	-	-	AMR for 3ph Commercial Customers
TOTAL	**9.0**	**17.0**	**15.0**	**0.8**	**0.0**	

APPENDIX 16D

PROPOSED PROJECT SCHEDULE 2004 - 2008

INFORMATION TECHNOLOGY

PROJECT DESCRIPTION	2004	2005	2006	2007	2008	REMARKS
	$M	$M	$M	$M	$M	
Meter Reading Project	1.4	-	-	-	-	Acquisition of new hand-held terminals.
Financials Project/Upgrade	6.7	-	-	-	-	Migration to version 8.4
Online Cash Receipting System	3.0	-	-	-	-	Online Revenue collection system
Laser Printer for Billing System	1.0	-	-	-	-	Additional printer required to print barcodes on bills.
Time Clocks for Payroll System	1.7	-	-	-	-	Automated timeclocks required to replace mechanical clocks.
Banner CIS Upgrade	3.0	-	-	-	-	Required for implementation of web-based system.
Interactive Voice Response	0.6	-	-	-	-	Required for implementation of next phase - availability of more information and the automated calling out to customers.
Computer Equipment	3.5	-	-	-	-	Acquisition of PCs to support new upgraded systems
Software Licences	3.0	3.0	3.0	3.0	3.0	Purchase of new and additional software licences as required.
Networking Equipment	2.4	2.4	2.4	2.4	2.4	Purchase of network equipment (switches, routers, cables, etc.) as
Server Acquisition and Upgrade	3.0	3.0	3.0	3.0	3.0	To facilitate the growth of the databases and files and new versions of software, the 29 servers may be upgraded (with additional processors, disks, memory, etc.) or replaced.
Automatic Metering & Communication System	1.0	5.0	5.0	-	-	Automatic Meting & Communication System
Banner Servers	2.5	-	-	-	-	To replace current BANNER servers
HRIS System	3.7	5.0	-	-	-	HRIS System
H/Resources Servers	1.5	-	-	-	-	H/Resources Servers
Fire Extinguishing System for Computer Room	0.6	-	-	-	-	The environment unfriendly Halon system is to be replaced.
Disaster Recovery	1.0	-	-	-	-	IS Contingency Plan
Computer Kiosks	0.6	-	-	-	-	Two kiosks will be placed in each Area for the field workers
Document Management System	0.5	1.0	-	-	-	Purchase of a record and information management system.
Computerised Maintenance Management Systems	0.6	0.6	-	-	-	Computerised Maintenance Management Systems
CMMS Project Hardware	-	1.0				CMMS Project Hardware
TOTAL	**41.2**	**21.0**	**13.4**	**8.4**	**8.4**	

APPENDIX 16E

PROPOSED PROJECT SCHEDULE 2003 - 2008

COMMERCIAL DEPARTMENT

PROJECT DESCRIPTION	2004 $M	2005 $M	2006 $M	2007 $M	2008 $M
Call Centre Consolidation and the development of Customer Relationship Management Policies	2.0	1.0	0.0	0.0	0.0
Introduction of Electronic Bill Presentment and Payment	0.0	0.0	0.0	3.0	0.0
TOTAL	**2.0**	**1.0**	**0.0**	**3.0**	**0.0**

APPENDIX 16F
PROPOSED PROJECT SCHEDULE 2004 - 2008
CONTROL AND COMMUNICATIONS DEPARTMENT

PROJECT DESCRIPTION	2004	2005	2006	2007	2008	REMARKS
	$M	$M	$M	$M	$M	
Microwave Radio Replacement	1.0	20.0	10.0	0.0	0.0	Replace obsolete 6GHz digital microwave radio system
Northern Area Fibre Development	3.6	0.0	0.0	0.0	0.0	Replace copper pilot cables in the Northern Area with fibre optic cable
Eastern Area Fibre Development	6.9	0.0	0.0	0.0	0.0	Replace copper pilot cables in the Eastern Area with fibre optic cable
Central Area Fibre Development	2.1	0.0	0.0	0.0	0.0	Expand fibre optic communication system in the Central Area.
Southern Area Fibre Development	1.7	0.0	0.0	0.0	0.0	Construct fibre optic communication system in the Southern Area
Tobago Fibre Development	1.7	0.0	0.0	0.0	0.0	Develop Trinidad - Tobago fibre optic communication system
Replacement of Older RTU's	0.8	0.0	0.0	0.0	0.0	Replacement of Older RTU's
Back up Control Room	1.9	0.0	0.0	0.0	0.0	Back up Control Room
South Trinidad Communications System	1.0	0.0	0.0	0.0	0.0	South Trinidad Communications System
Mobile Trunking Radio System	0.0	0.0	20.0	0.0	0.0	Replace existing VHF/UHF mobile radio with trunked radio system
Voice Trunking System	0.0	0.5	0.0	0.0	0.0	Voice Trunking System
TOTAL	**20.6**	**20.5**	**30.0**	**0.0**	**0.0**	

APPENDIX 16G

PROPOSED PROJECT SCHEDULE 2003 - 2008

ADMINISTRATION AND GENERAL

PROJECT DESCRIPTION	2004	2005	2006	2007	2008
	$M	$M	$M	$M	$M
Refurbishment of Head Office	3.9	-	-	-	-
3-phase Backup Generator	2.0	-	-	-	-
Substation Load Monitoring	1.2	2.0	2.0		
Load Research Programme	0.2	1.9	-	-	-
Dow Village Warehouse	6.0	-	-	-	-
Pole Lifting Equipment	2.8	-	-	-	-
TOTAL	**16.1**	**3.9**	**2.0**	**0.0**	**0.0**

APPENDIX 17
ANALYSIS OF EXPENDITURE FORECAST 2004-2008

DESCRIPTION	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
GENERATION	**$**	**$**	**$**	**$**	**$**
Conversion Costs	748,904,669	818,480,411	876,704,882	932,349,026	975,790,777
Fuel	473,447,355	509,325,000	570,559,000	562,708,000	598,375,000
Operations	3,106,445	3,026,788	3,057,056	3,094,143	3,125,085
Security	0	0	0	0	0
Maintenance	2,076,494	3,064,945	3,090,595	3,122,784	3,149,012
Rents,Taxes and Insurance	424,529	425,773	429,681	434,186	438,178
	1,227,959,492	**1,334,322,917**	**1,453,841,214**	**1,501,708,139**	**1,580,878,052**
TRANSMISSION					
Maintenance	4,217,639	4,810,930	4,939,345	4,973,397	5,108,113
	4,217,639	**4,810,930**	**4,939,345**	**4,973,397**	**5,108,113**
DISTRIBUTION					
Customer Services	25,958,935	26,245,511	26,473,718	26,701,925	26,938,944
Operations	84,500,561	84,596,866	85,362,835	86,128,803	86,910,090
Maintenance	65,049,338	61,649,094	62,205,586	62,762,076	63,329,696
Security	19,603,530	19,084,308	19,245,151	19,245,151	19,407,602
Rates,Taxes and Insurance	9,846,673	10,143,960	10,234,400	10,325,569	10,418,825
	204,959,037	**201,719,739**	**203,521,690**	**205,163,524**	**207,005,157**
TOTAL - TRANSMISSION & DISTRIBUTION	**209,176,676**	**206,530,669**	**208,461,035**	**210,136,921**	**212,113,270**
ENGINEERING ADMINISTRATION	**12,949,359**	**12,903,837**	**13,186,656**	**13,424,147**	**13,724,328**
ADMINISTRATION & GENERAL					
Customer Services	18,350,731	18,528,855	18,629,144	18,629,144	18,730,435
Maintenance	6,043,634	6,401,960	6,450,980	6,450,980	6,500,490
General Expenses	89,504,508	90,630,478	91,561,596	91,858,675	92,871,004
Security	12,401,985	15,606,345	15,702,408	15,702,408	15,799,432
Rates,Taxes and Insurance	2,183,744	2,287,922	2,307,291	2,307,802	2,327,880
	128,484,602	**133,455,560**	**134,651,419**	**134,949,009**	**136,229,241**
Depreciation	80,411,289	82,201,905	84,202,635	86,764,661	89,332,308
Interest	88,954,923	123,000,000	138,000,000	153,000,000	138,000,000
	169,366,212	**205,201,905**	**222,202,635**	**239,764,661**	**227,332,308**
Total Expenditure	**1,747,936,341**	**1,892,414,888**	**2,032,342,959**	**2,099,982,877**	**2,170,277,199**

	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Conversion Costs	748,904,669	818,480,411	876,704,882	932,349,026	975,790,777
Fuel	473,447,355	509,325,000	570,559,000	562,708,000	598,375,000
Operations	87,607,006	87,623,654	88,419,891	89,222,946	90,035,175
Maintenance	77,387,105	75,926,929	76,686,506	77,309,237	78,087,311
Customer Services	44,309,666	44,774,366	45,102,862	45,331,069	45,669,379
Security	32,005,515	34,690,653	34,947,559	34,947,559	35,207,034
Engineering Administration	12,949,359	12,903,837	13,186,656	13,424,147	13,724,328
Administration & General	89,504,508	90,630,478	91,561,596	91,858,675	92,871,004
Rents,Rates and Insurance	12,454,946	12,857,655	12,971,372	13,067,557	13,184,883
	1,578,570,129	**1,687,212,983**	**1,810,140,324**	**1,860,218,216**	**1,942,944,891**
Depreciation	80,411,289	82,201,905	84,202,635	86,764,661	89,332,308
Interest	88,954,923	123,000,000	138,000,000	153,000,000	138,000,000
Total Expenditure	**1,747,936,341**	**1,892,414,888**	**2,032,342,959**	**2,099,982,877**	**2,170,277,199**

APPENDIX 18A

INCOME STATEMENT FORECAST 2004-2008

Description	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Sales - GWh	6,355,107,001	6,508,000,000	6,760,000,000	6,962,000,000	7,192,000,000
Average Revenue per kWh -cts	23.97	23.97	23.97	23.97	23.97
INCOME	**$**	**$**	**$**	**$**	**$**
Sales of Electricity	1,523,601,930	1,560,257,185	1,620,672,799	1,669,101,187	1,724,242,421
Other Income	149,239,118	151,655,885	153,012,445	154,369,003	155,752,693
TOTAL INCOME	1,672,841,048	1,711,913,070	1,773,685,244	1,823,470,190	1,879,995,114
EXPENDITURE					
Generation	1,227,959,492	1,334,322,917	1,453,841,214	1,501,708,139	1,580,878,052
Transmission	4,217,639	4,810,930	4,939,345	4,973,397	5,108,113
Distribution	204,959,037	201,719,739	203,521,690	205,163,524	207,005,157
Engineering Administration	12,949,359	12,903,837	13,186,656	13,424,147	13,724,328
Administration & General	128,484,602	133,455,560	134,651,419	134,949,009	136,229,241
Depreciation	80,411,289	82,201,905	84,202,635	86,764,661	89,332,308
Interest	88,954,923	123,000,000	138,000,000	153,000,000	138,000,000
TOTAL EXPENDITURE	1,747,936,341	1,892,414,888	2,032,342,959	2,099,982,877	2,170,277,199
NET SURPLUS/(DEFICIT)	**(75,095,293)**	**(180,501,818)**	**(258,657,715)**	**(276,512,687)**	**(290,282,085)**
Rate Base	1,594,015,721	1,939,922,212	2,139,112,234	2,336,579,630	2,536,328,354
Return on Rate Base - %	**-4.71%**	**-9.30%**	**-12.09%**	**-11.83%**	**-11.44%**

APPENDIX 18B

INCOME STATEMENT BY RESOURCE CATEGORY 2004-2008

Description		Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Sales - GWh		6,355,107,001	6,508,000,000	6,760,000,000	6,962,000,000	7,192,000,000
Average Revenue per kWh -*cts*		23.97	23.97	23.97	23.97	23.97
INCOME		**$**	**$**	**$**	**$**	**$**
Sales of Electricity		1,523,601,930	1,560,257,185	1,620,672,799	1,669,101,187	1,724,242,421
Other Income		149,239,118	151,655,885	153,012,445	154,369,003	155,752,693
TOTAL INCOME		1,672,841,048	1,711,913,071	1,773,685,243	1,823,470,190	1,879,995,114
EXPENDITURE						
Conversion Cost	C,OUC	748,904,669	818,480,411	876,704,882	932,349,026	975,790,777
Fuel	C,OUC	473,447,355	509,325,000	570,559,000	562,708,000	598,375,000
Wages	V,OC	87,084,460	88,826,149	90,602,672	92,414,726	94,263,020
Salaries	V,OC	135,263,047	137,968,308	140,727,674	143,542,227	146,413,072
Employee Related Benefits	V,OC	51,572,876	51,830,740	52,089,894	52,350,344	52,612,095
Insurances	V,OC	11,227,450	11,617,884	11,720,202	11,802,867	11,907,546
Materials	V,OC	11,662,466	11,720,778	11,779,382	11,838,279	11,897,471
Services	V,OC	83,693,011	84,111,476	84,532,033	84,954,693	85,379,467
Rent, Rates and Taxes	V,OC	1,227,496	1,233,633	1,239,802	1,246,001	1,252,231
Depreciation	SC	80,411,289	82,201,905	84,202,635	86,764,661	89,332,308
Interest	C	88,954,923	123,000,000	138,000,000	153,000,000	138,000,000
Loss/(Gain) on Exchange		0	0	0	0	0
Accounting reallocations		(25,512,700)	(27,901,397)	(29,814,218)	(32,987,946)	(34,945,786)
TOTAL EXPENDITURE		1,747,936,342	1,892,414,888	2,032,343,958	2,099,982,878	2,170,277,200
NET SURPLUS/(DEFICIT)		**(75,095,294)**	**(180,501,817)**	**(258,658,714)**	**(276,512,688)**	**(290,282,086)**
Rate Base		1,594,015,721	1,939,922,212	2,139,112,234	2,336,579,630	2,536,328,354
Annual return		**-4.71%**	**-9.30%**	**-12.09%**	**-11.83%**	**-11.44%**

Fixed	F	2,000,000
Variable	V	
Contractual (Not fixed)	C	
Sunk Costs	SC	
Ongoing Controllable	OC	
Ongoing Uncontrollable	OUC	
One-off (Non-Recurring Costs)	OOFF	

APPENDIX 18C
INCOME STATEMENT BY ACTIVITY 2004-2008

Description	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Sales - GWh	6,355,107,001	6,508,000,000	6,760,000,000	6,962,000,000	7,192,000,000
Average Revenue per kWh -*cts*	23.97	23.97	23.97	23.97	23.97
INCOME	**$**	**$**	**$**	**$**	**$**
Sales of Electricity	1,523,601,930	1,560,257,185	1,620,672,799	1,669,101,187	1,724,242,421
Other Income	149,239,118	151,655,885	153,012,445	154,369,003	155,752,693
TOTAL INCOME	1,672,841,048	1,711,913,071	1,773,685,243	1,823,470,190	1,879,995,114
EXPENDITURE					
Conversion Costs	748,904,669	818,480,411	876,704,882	932,349,026	975,790,777
Fuel	473,447,355	509,325,000	570,559,000	562,708,000	598,375,000
Operations	87,607,007	92,041,694	92,970,472	93,910,045	94,862,887
Maintenance	77,387,105	75,926,929	76,686,506	77,309,238	78,087,311
Customer Services	44,309,665	44,774,366	45,102,862	45,331,068	45,669,379
Security	32,005,515	34,690,653	34,947,559	34,947,559	35,207,034
Engineering Administration	12,949,360	12,903,837	13,186,656	13,424,147	13,724,328
Administration & General	89,504,508	86,212,438	87,011,015	87,171,577	88,043,293
Rents,Rates and Insurance	12,454,946	12,857,655	12,972,371	13,067,557	13,184,883
Depreciation	80,411,289	82,201,905	84,202,635	86,764,661	89,332,308
Interest	88,954,923	123,000,000	138,000,000	153,000,000	138,000,000
TOTAL EXPENDITURE	1,747,936,341	1,892,414,888	2,032,343,958	2,099,982,878	2,170,277,200
NET SURPLUS/(DEFICIT)	**(75,095,293)**	**(180,501,817)**	**(258,658,715)**	**(276,512,688)**	**(290,282,086)**
Rate Base	1,594,015,721	1,939,922,212	2,139,112,234	2,336,579,630	2,536,328,354
Annual Return	**-4.71%**	**-9.30%**	**-12.09%**	**-11.83%**	**-11.44%**

APPENDIX 18D

BALANCE SHEET FORECAST 2004-2008

DESCRIPTION	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
ASSETS	**$M**	**$M**	**$M**	**$M**	**$M**
Non-Current Assets					
Property, plant and equipment	1,289.3	1,612.1	1,788.7	1,972.3	2,157.6
Investment in subsidiary	246.3	246.3	246.3	246.3	246.3
Convertible redeemable debenture stock	223.4	210.7	198.1	185.4	172.8
	1,758.9	2,069.2	2,233.0	2,404.0	2,576.7
Current Assets					
Inventories	96.4	101.5	106.9	112.6	118.6
Accounts receivable	617.2	550.5	609.2	674.1	745.9
Cash and cash equivalents	50.0	75.0	60.0	60.0	60.0
	763.6	727.0	776.1	846.7	924.6
Total Assets	**2,522.5**	**2,796.2**	**3,009.1**	**3,250.7**	**3,501.2**
EQUITY AND LIABILITIES					
Capital and Reserves					
Capital funds	1,368.1	1,368.1	1,368.1	1,368.1	1,368.1
Reserves	201.4	208.5	215.8	223.4	231.2
Accumulated deficit	(1,037.7)	(1,218.2)	(1,476.8)	(1,753.3)	(2,043.6)
	531.9	358.4	107.1	(161.9)	(444.3)
Non-Current Liabilities					
Customers' service deposits	34.8	38.5	42.7	47.5	53.9
Medium and long term financing	1,201.4	1,230.7	966.7	787.7	609.0
Retirement benefit obligations	126.8	130.9	135.1	139.5	144.0
	1,363.0	1,400.1	1,144.5	974.6	806.9
Current Liabilities					
Short term Loans	0.0	234.4	884.8	1,440.9	2,115.3
Bank advances	47.5	95.4	100.0	200.0	200.0
Current portion of medium and long term financing	35.3	139.6	180.2	179.1	178.6
Accounts payable	442.0	464.1	487.3	511.6	537.2
Due to subsidiary	103.0	104.1	105.2	106.4	107.5
	627.6	1,037.6	1,757.5	2,438.0	3,138.7
Total Equity and Liabilities	**2,522.5**	**2,796.2**	**3,009.1**	**3,250.7**	**3,501.2**

APPENDIX 19

SUMMARY OF CAPITAL EXPENDITURE AND OPERATING COSTS

DESCRIPTION	2004	2005	2006	2007	2008
	$M	$M	$M	$M	$M
Operating Costs					
Total Operating Costs	**1,747.9**	**1,892.4**	**2,032.3**	**2,100.0**	**2,170.3**
Capital Expenditure					
Protection and Meter	12.4	17.0	15.0	0.8	1.0
Control and Communications	23.7	48.2	34.5	1.0	1.0
Commercial	2.2	1.1	1.0	3.0	1.0
Transmission	202.9	134.0	51.5	14.2	17.7
Distribution	271.3	198.2	128.3	171.5	171.2
Generation Tobago	4.6	2.0	2.0	2.0	2.0
Information Technology	48.7	20.0	8.0	10.9	10.9
Administration and General	39.4	22.0	17.0	15.0	10.0
Rural Electrification	5.0	-	-	-	-
National Social Improvement Programme	23.0	-	-	-	-
Total Capital Expenditure	**633.2**	**442.5**	**257.3**	**218.5**	**214.8**
Total Operating Costs and Capital Expenditure	**2,381.2**	**2,334.9**	**2,289.6**	**2,318.5**	**2,385.1**

APPENDIX 20

PERFORMANCE INDICATORS 2004 TO 2008 (without rate increase)

	Indicator	Definition	2004	2005	2006	2007	2008	Best Practice*
a	Customers/Employees	Total no. of customers/Total no. of employees	149	149	149	149	149	142
b	Consumption per Capita	Total kWh sales/Total population	4,708	4,933	5,120	5,234	5,354	1,277
c	Service Coverage(%)	No. of customers/No. of households in T&T	97.00%	97.00%	98.00%	98.00%	99.00%	99.50%
d	Working Ratio	Operating costs(excluding depreciation & interest)/Revenue	0.87	0.85	0.84	0.82	0.81	0.70
e	Average Revenue per kWh($)	Total revenue/Total no. of kWh sold	0.30	0.31	0.32	0.33	0.34	0.38
f	Average Sales per kWh($)	Total revenue from sales/Total no. of kWh sold	0.27	0.28	0.30	0.31	0.32	0.38
g	Sales per employee($)	Total revenue from sales/No. of employees	716,309	773,431	826,589	856,974	895,197	3,586,551
h	Sales per employee(kWh)	Total kWh sales/No. of employees	2,639,500	2,713,923	2,764,120	2,773,746	2,786,229	10,070,235
I	Total System Losses(%)	Difference between MWH purchased and sold	8.4%	8.4%	8.5%	8.6%	8.7%	<12%
j	Operating Ratio	Operating costs(including depreciation & interest)/Revenue	0.97	0.95	0.93	0.91	0.89	0.75
k	Debt Service Coverage Ratio	Revenue/Medium and long term debt	1.40	1.54	1.87	2.33	3.04	2.25
l	Operating Cost per Customer($)	Total operating costs/Total no. of customers	5,057.88	5,322.32	5,570.96	5,613.78	5,740.74	11,510.73

* Average for Latin America and the Caribbean as provided by the Regulated Industries Commission (RIC)

APPENDIX 21A

PURCHASED POWER ADJUSTMENT CLAUSE

Purchased Power Adjustment Charge (PPAC) is an automatic adjustment charge which allows a Utility to automatically change the rates charged to customers to track changes in the cost of a predetermined item or items. These items are usually, in the short run, outside of the control of the Utility. The intent of the Automatic Adjustment Charge is to neutralise the effects of cost changes over which the Utility has little or no control.
With respect to TTEC, the PPAC recovers the changes in the monthly cost of purchasing electricity from PowerGen and Trinity Power and any other Independent Power Producer (IPP), on a per kWh basis.

The following formula is applied in computing the PPA charge:-

PPA = (Pm / Epm) - BC

where:

PPA = Purchased power adjustment to be applied to energy usage in the succeeding billing period.

Pm = Current month's net cost of purchased power.

Epm = Net energy purchased.

BC = Pb / Epb = base power cost

where:

Pb and Epb are purchased power and net energy purchased for the base period - 2003

PPA for the period 2004 to 2008 is projected as follows:

Projected Average PPA

	2003 $	2004 $	2005 $	2006 $	2007 $	2008 $
Wholesale Power Costs	702,265,519	766,609,799	818,480,411	876,704,882	932,349,026	975,790,777
Energy Purchased(kWh)	6,392,141,000	6,663,000,000	6,970,000,000	7,240,000,000	7,409,000,000	7,587,000,000
Average Cost(¢/kWh)	0.1099	0.1151	0.1174	0.1211	0.1258	0.1286
Base Cost (¢/kWh)	0.1099	0.1099	0.1099	0.1099	0.1099	0.1099
PPA (¢/kWh)	0.0000	0.0052	0.0076	0.0112	0.0160	0.0187

APPENDIX 21B

FUEL CHARGE - FORECAST 2005

	MONTHLY				ANNUAL
	QUANTITY		**COST**		**2005**
	(BTUs X 10^6)		$		$
GAS					
Heating Value PowerGen	5,794,162.85		31,852,715		382,232,580
Trinity Power	1,605,740.98		8,827,368		105,928,420
	7,633,537.58		41,964,417		503,573,000
Impost					
Transportation					
Fuel					
JET 'A'					
DIESEL					
(Tobago)	11,705		479,333		5,752,000
	7,645,242.67	**(B1)**	**42,443,750.00**	**(A)**	**509,325,000**
QUANTITY IN KJs (B2)	B1 x 1.0551 x 10^6		8,066,495.54	KJs x 10^6	
AVERAGE GROSS PRICE PER 1,055,100KJs OF FUEL(C)	A/B2 x 1.0551		555.20000	cents	
AVERAGE GROSS PRICE					
INCREASE IN FUEL ABOVE	C - 533		22.2	cents	
218.9 CENTS (D)					
INCREASE IN CHARGE PER KWH	D x 0.0154		0.3419	cents	
FUEL CHARGE ADJUSTMENT			**0.3419**	**cents**	

APPENDIX 21C

FUEL CHARGE - FORECAST 2006

	MONTHLY			ANNUAL
	QUANTITY (BTUs X 10^6)	COST $		2006 $
GAS				
Heating Value PowerGen	6,012,761.84	34,376,463		412,517,552
Trinity Power	1,666,321.49	9,526,777		114,321,319
	7,832,684.58	44,781,417		537,377,000
Impost				
Transportation				
Fuel				
JET 'A'				
DIESEL				
(Tobago)	67,529	2,765,167		33,182,000
	7,900,213.75 (B1)	**47,546,583.33**	**(A)**	570,559,000
QUANTITY IN KJs (B2)	B1 x 1.0551 x 10^6	8,335,515.53	KJs x 10^6	
AVERAGE GROSS PRICE PER 1,055,100KJs OF FUEL(C)	A/B2 x 1.0551	601.800	cents	
AVERAGE GROSS PRICE				
INCREASE IN FUEL ABOVE	C - 533	68.800	cents	
218.9 CENTS (D) INCREASE IN CHARGE PER KWH	D x 0.0154	1.0595	cents	
FUEL CHARGE ADJUSTMENT		**1.0595**	**cents**	

APPENDIX 21D

FUEL CHARGE - FORECAST 2007

	MONTHLY				ANNUAL
	QUANTITY		**COST**		**2007**
	(BTUs X 10^6)		$		$
GAS					
Heating Value PowerGen	6,254,618.37		37,189,586		446,275,026
Trinity Power	1,733,347.39		10,306,380		123,676,555
	7,886,445.92		46,892,333		562,708,000
Impost					
Transportation					
Fuel					
JET 'A'					
DIESEL					
(Tobago)	0		0		0
	7,886,445.92	**(B1)**	**46,892,333.33**	**(A)**	**562,708,000**

QUANTITY IN KJs (B2)	B1 x 1.0551 x 10^6	8,320,989.09	KJs x 10^6
AVERAGE GROSS PRICE PER 1,055,100KJs OF FUEL(C)	A/B2 x 1.0551	594.600	cents
AVERAGE GROSS PRICE			
INCREASE IN FUEL ABOVE	C - 533	61.600	cents
218.9 CENTS (D) INCREASE IN CHARGE PER KWH	D x 0.0154	0.9486	cents
FUEL CHARGE ADJUSTMENT		**0.9486**	**cents**

APPENDIX 21E

FUEL CHARGE - FORECAST 2008

	MONTHLY		ANNUAL
	QUANTITY (BTUs X 10^6)	**COST** $	**2008** $
GAS			
Heating Value PowerGen	6,381,846.32	39,463,918	473,567,020
Trinity Power	1,768,606.17	10,936,667	131,240,007
	8,063,382.08	49,864,583	598,375,000
Impost			
Transportation			
Fuel			
JET 'A'			
DIESEL			
(Tobago)	0	0	0
	8,063,382.08 (B1)	**49,864,583.33 (A)**	598,375,000
QUANTITY IN KJs (B2)	B1 x 1.0551 x 10^6	8,507,674.44 KJs x 10^6	
AVERAGE GROSS PRICE PER 1,055,100KJs OF FUEL(C)	A/B2 x 1.0551	618.400 cents	
AVERAGE GROSS PRICE			
INCREASE IN FUEL ABOVE	C - 533	85.400 cents	
218.9 CENTS (D) INCREASE IN CHARGE PER KWH	D x 0.0154	1.3152 cents	
FUEL CHARGE ADJUSTMENT		**1.3152 cents**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-A

Energy Billed 500 kWh   Select Year 2004

Sample Bill - Based on 2004 Rate Application

Energy Charge	¢/kWh	kWh	Cost $
Tier 1			
- fuel	7.64		
- other	27.50		
Tier 1 total	35.14	500	175.72
Tier 2	35.14	0	-
Tier 3	35.14	0	-
Base Energy Cost			**175.72**
Customer Charge			42.15
Fuel Adjustment	0.00	500	-
Ex. Rate Adjustment	0.00	500	-
PPA Adjustment	0.00	500	-
Subtotal			**217.87**
VAT @15%			32.68
Total			**$ 250.55**

Comparison Bill Based on 2003 Tariff

Energy Charge	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	18.59		
Base rate total	21.96	500	109.80
Base Energy Cost			**109.80**
Customer Charge			4.00
Fuel Adjustment	0.00	500	-
Ex. Rate Adjustment	0.00	500	-
PPA Adjustment	0.00	500	-
Subtotal			**113.80**
VAT @15%			17.07
Total			**$ 130.87**

Change: **$119.68**
91.4%

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-A

Energy Billed 500 kWh Select Year 2004

Sample Bill - Based on 2004 Rate Application				Comparison Bill Based on 2003 Tariff			
Energy Charge	**¢/kWh**	**kWh**	**Cost $**	**Energy Charge**	**¢/kWh**	**kWh**	**Cost $**
Tier 1				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	13.81			- other	18.59		
Tier 1 total	21.45	500	107.25	Base rate total	21.96	500	109.80
Tier 2	31.00	0	-				
Tier 3	44.50	0	-				
Base Energy Cost			**107.25**	**Base Energy Cost**			**109.80**
Customer Charge			4.00	Customer Charge			4.00
Fuel Adjustment	0.00	500	-	Fuel Adjustment	0.00	500	-
Ex. Rate Adjustment	0.00	500	-	Ex. Rate Adjustment	0.00	500	-
PPA Adjustment	0.52	500	2.60	PPA Adjustment	0.00	500	-
Subtotal			**113.85**	**Subtotal**			**113.80**
VAT @15%			17.08	VAT @15%			17.07
Total			**$ 130.93**	**Total**			**$ 130.87**

Change: **$0.06**
0.0%

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-A

Energy Billed *1,500* kWh   Select Year 2004

Sample Bill - Based on 2004 Rate Application				Comparison Bill Based on 2003 Tariff			
Energy Charge	**¢/kWh**	**kWh**	**Cost $**	**Energy Charge**	**¢/kWh**	**kWh**	**Cost $**
Tier 1				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	27.50			- other	18.59		
Tier 1 total	35.14	500	175.72	Base rate total	21.96	1,500	329.40
Tier 2	35.14	1,000	351.44				
Tier 3	35.14	0	-				
Base Energy Cost			**527.16**	**Base Energy Cost**			**329.40**
Customer Charge			42.15	Customer Charge			4.00
Fuel Adjustment	0.00	1,500	-	Fuel Adjustment	0.00	1,500	-
Ex. Rate Adjustment	0.00	1,500	-	Ex. Rate Adjustment	0.00	1,500	-
PPA Adjustment	0.00	1,500	-	PPA Adjustment	0.00	1,500	-
Subtotal			**569.31**	**Subtotal**			**333.40**
VAT @15%			85.40	VAT @15%			50.01
Total			**$ 654.71**	**Total**			**$ 383.41**

Change: **$271.30**
70.8%

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission

63 Frederick Street, Port of Spain

Rate-A

Energy Billed *1,500* kWh Select Year 2004

Sample Bill - Based on 2004 Rate Application

Energy Charge	¢/kWh	kWh	Cost $
Tier 1			
- fuel	7.64		
- other	13.81		
Tier 1 total	21.45	500	107.25
Tier 2	31.00	1,000	310.00
Tier 3	44.50	0	-
Base Energy Cost			**417.25**
Customer Charge			4.00
Fuel Adjustment	0.00	1,500	-
Ex. Rate Adjustment	0.00	1,500	-
PPA Adjustment	0.52	1,500	7.80
Subtotal			**429.05**
VAT @15%			64.36
Total			**$ 493.41**

Comparison Bill Based on 2003 Tariff

Energy Charge	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	18.59		
Base rate total	21.96	1,500	329.40
Base Energy Cost			**329.40**
Customer Charge			4.00
Fuel Adjustment	0.00	1,500	-
Ex. Rate Adjustment	0.00	1,500	-
PPA Adjustment	0.00	1,500	-
Subtotal			**333.40**
VAT @15%			50.01
Total			**$ 383.41**

Change: **$110.00**

28.7%

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-A

Energy Billed *2,500* kWh Select Year 2004

Sample Bill - Based on 2004 Rate Application

Energy Charge	¢/kWh	kWh	Cost $
Tier 1			
- fuel	7.64		
- other	27.50		
Tier 1 total	35.14	500	175.72
Tier 2	35.14	1,000	351.44
Tier 3	35.14	1,000	351.44
Base Energy Cost			**878.60**
Customer Charge			42.15
Fuel Adjustment	0.00	2,500	-
Ex. Rate Adjustment	0.00	2,500	-
PPA Adjustment	0.00	2,500	-
Subtotal			**920.75**
VAT @15%			138.11
Total			**$ 1,058.86**

Comparison Bill Based on 2003 Tariff

Energy Charge	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	18.59		
Base rate total	21.96	2,500	549.00
Base Energy Cost			**549.00**
Customer Charge			4.00
Fuel Adjustment	0.00	2,500	-
Ex. Rate Adjustment	0.00	2,500	-
PPA Adjustment	0.00	2,500	-
Subtotal			**553.00**
VAT @15%			82.95
Total			**$ 635.95**

Change: **$422.91**
66.5%

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-A

Energy Billed *2,500* kWh   Select Year 2004

Sample Bill - Based on 2004 Rate Application				Comparison Bill Based on 2003 Tariff			
Energy Charge	**¢/kWh**	**kWh**	**Cost $**	**Energy Charge**	**¢/kWh**	**kWh**	**Cost $**
Tier 1				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	13.81			- other	18.59		
Tier 1 total	21.45	500	107.25	Base rate total	21.96	2,500	549.00
Tier 2	31.00	1,000	310.00				
Tier 3	44.50	1,000	445.00				
Base Energy Cost			**862.25**	**Base Energy Cost**			**549.00**
Customer Charge			4.00	Customer Charge			4.00
Fuel Adjustment	0.00	2,500	-	Fuel Adjustment	0.00	2,500	-
Ex. Rate Adjustment	0.00	2,500	-	Ex. Rate Adjustment	0.00	2,500	-
PPA Adjustment	0.52	2,500	13.00	PPA Adjustment	0.00	2,500	-
Subtotal			**879.25**	**Subtotal**			**553.00**
VAT @15%			131.89	VAT @15%			82.95
Total			**$ 1,011.14**	**Total**			**$ 635.95**

Change: **$375.19**
59.0%

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-B

Energy Billed *1,000* kWh   Select Year 2007

Sample Bill - Based on 2004 Rate Application

Energy Charge	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	26.32		
Base rate total	33.96	1,000	339.60
Energy Cost			**339.60**
Customer Charge			48.44
Fuel Adjustment	0.00	1,000	-
Ex. Rate Adjustment	0.00	1,000	-
PPA Adjustment	0.00	1,000	-
Subtotal			**388.05**
VAT @15%			58.21
Total			**$ 446.26**

Comparison Bill Based on 2003 Tariff

Energy Charge	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	20.09		
Base rate total	23.46	1,000	234.60
Energy Cost			**234.60**
Customer Charge			20.00
Fuel Adjustment	0.00	1,000	-
Ex. Rate Adjustment	0.00	1,000	-
PPA Adjustment	0.00	1,000	-
Subtotal			**254.60**
VAT @15%			38.19
Total			**$ 292.79**

Change before VAT: $133.45   52.4%
Change after VAT: $153.47

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-B

Energy Billed *1,000* kWh   Select Year 2007

Sample Bill - Based on 2004 Rate Application				Comparison Bill Based on 2003 Tariff			
Energy Charge	**¢/kWh**	**kWh**	**Cost $**	**Energy Charge**	**¢/kWh**	**kWh**	**Cost $**
Base Rate				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	24.96			- other	20.09		
Base rate total	32.60	1,000	326.00	Base rate total	23.46	1,000	234.60
Energy Cost			**326.00**	**Energy Cost**			**234.60**
Customer Charge			46.00	Customer Charge			20.00
Fuel Adjustment	0.95	1,000	9.49	Fuel Adjustment	0.00	1,000	-
Ex. Rate Adjustment	0.00	1,000	-	Ex. Rate Adjustment	0.00	1,000	-
PPA Adjustment	1.60	1,000	16.00	PPA Adjustment	0.00	1,000	-
Subtotal			**397.49**	**Subtotal**			**254.60**
VAT @15%			59.62	VAT @15%			38.19
Total			**$ 457.11**	**Total**			**$ 292.79**

Change before VAT:	$142.89	56.1%
Change after VAT:	$164.32	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-B

Energy Billed *2,500* kWh   Select Year 2007

Sample Bill - Based on 2004 Rate Application				Comparison Bill Based on 2003 Tariff			
Energy Charge	**¢/kWh**	**kWh**	**Cost $**	**Energy Charge**	**¢/kWh**	**kWh**	**Cost $**
Base Rate				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	26.32			- other	20.09		
Base rate total	33.96	2,500	849.01	Base rate total	23.46	2,500	586.50
Energy Cost			**849.01**	**Energy Cost**			**586.50**
Customer Charge			48.44	Customer Charge			20.00
Fuel Adjustment	0.00	2,500	-	Fuel Adjustment	0.00	2,500	-
Ex. Rate Adjustment	0.00	2,500	-	Ex. Rate Adjustment	0.00	2,500	-
PPA Adjustment	0.00	2,500	-	PPA Adjustment	0.00	2,500	-
Subtotal			**897.45**	**Subtotal**			**606.50**
VAT @15%			134.62	VAT @15%			90.98
Total			**$ 1,032.07**	**Total**			**$ 697.48**

Change before VAT: $290.95 48.0%
Change after VAT: $334.59

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-B

Energy Billed *2,500* kWh   Select Year 2007

Sample Bill - Based on 2004 Rate Application				Comparison Bill Based on 2003 Tariff			
Energy Charge	**¢/kWh**	**kWh**	**Cost $**	**Energy Charge**	**¢/kWh**	**kWh**	**Cost $**
Base Rate				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	24.96			- other	20.09		
Base rate total	32.60	2,500	815.00	Base rate total	23.46	2,500	586.50
Energy Cost			**815.00**	**Energy Cost**			**586.50**
Customer Charge			46.00	Customer Charge			20.00
Fuel Adjustment	0.95	2,500	23.72	Fuel Adjustment	0.00	2,500	-
Ex. Rate Adjustment	0.00	2,500	-	Ex. Rate Adjustment	0.00	2,500	-
PPA Adjustment	1.60	2,500	40.00	PPA Adjustment	0.00	2,500	-
Subtotal			**924.72**	**Subtotal**			**606.50**
VAT @15%			138.71	VAT @15%			90.98
Total			**$ 1,063.43**	**Total**			**$ 697.48**

Change before VAT: $318.22 52.5%
Change after VAT: $365.95

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D1

Tariff Options? ◉ D1 ○ B1 ○ B

Tariff Year: 2008

Customer Name: Supermarket #3

Reduce Reserve? ◉ No ○ Yes

PF Improved? ◉ No ○ Yes

150	**kVA reserve**	95	**kW usage**	20,000	**kWh sales**
112	**kVA usage**	0.850	**power factor**	0.292	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	4.13		
Base rate total	11.77	20,000	2,353.91
Fuel Adjustment	0.00	20,000	-
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	0.00	20,000	-
Energy Cost			**2,353.91**
Customer Charge			**-**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	79.20	113	8,910.16
Subtotal before VAT			**11,264.08**
VAT @15%			1,689.61
Total			**$ 12,953.69**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	20.34		
Base rate total	23.71	20,000	4,742.00
Fuel Adjustment	0.00	20,000	-
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	0.00	20,000	-
Energy Cost			**4,742.00**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	113	2,446.88
Subtotal before VAT			**7,188.88**
VAT @15%			1,078.33
Total			**$ 8,267.21**

Change before VAT: $4,075 56.7%
Change after VAT: $4,686

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D1

Tariff Options? (•) D1 ( ) B1 ( ) B

Tariff Year: 2008

Customer Name: Supermarket #3

Reduce Reserve? (•) No ( ) Yes

150	**kVA reserve**	95	**kW usage**	20,000	**kWh sales**
112	**kVA usage**	0.850	**power factor**	0.292	**Load factor**

PF Improved? (•) No ( ) Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	13.46		
Base rate total	21.10	20,000	4,220.00
Fuel Adjustment	1.32	20,000	263.04
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	1.87	20,000	374.00
Energy Cost			**4,857.04**
Customer Charge			-
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	63.00	113	7,087.50
Subtotal before VAT			**11,944.54**
VAT @15%			1,791.68
Total			**$ 13,736.22**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	20.34		
Base rate total	23.71	20,000	4,742.00
Fuel Adjustment	0.00	20,000	-
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	0.00	20,000	-
Energy Cost			**4,742.00**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	113	2,446.88
Subtotal before VAT			**7,188.88**
VAT @15%			1,078.33
Total			**$ 8,267.21**

Change before VAT:	**$4,756**	**66.2%**
Change after VAT:	**$5,469**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D1

Tariff Options? ◉ D1 ○ B1 ○ B

Tariff Year: 2008

Customer Name: Supermarket #3

Reduce Reserve? ◉ No ○ Yes

PF Improved? ◉ No ○ Yes

150	**kVA reserve**	95	**kW usage**	20,000	**kWh sales**
112	**kVA usage**	0.850	**power factor**	0.292	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	4.13		
Base rate total	11.77	20,000	2,353.91
Fuel Adjustment	0.00	20,000	-
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	0.00	20,000	-
Energy Cost			**2,353.91**
Customer Charge			-
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	79.20	113	8,910.16
Subtotal before VAT			**11,264.08**
VAT @15%			1,689.61
Total			**$ 12,953.69**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	20.34		
Base rate total	23.71	20,000	4,742.00
Fuel Adjustment	0.00	20,000	-
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	0.00	20,000	-
Energy Cost			**4,742.00**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	113	2,446.88
Subtotal before VAT			**7,188.88**
VAT @15%			1,078.33
Total			**$ 8,267.21**

Change before VAT:	**$4,075**	**56.7%**
Change after VAT:	**$4,686**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D1

Tariff Options? (●) D1 ( ) B1 ( ) B

Tariff Year: 2008

Customer Name: Supermarket #3

Reduce Reserve? (●) No ( ) Yes

PF Improved? (●) No ( ) Yes

150	**kVA reserve**	95	**kW usage**	20,000	**kWh sales**
112	**kVA usage**	0.850	**power factor**	0.292	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	13.46		
Base rate total	21.10	20,000	4,220.00
Fuel Adjustment	1.32	20,000	263.04
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	1.87	20,000	374.00
Energy Cost			**4,857.04**
Customer Charge			**-**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	63.00	113	7,087.50
Subtotal before VAT			**11,944.54**
VAT @15%			1,791.68
Total			**$ 13,736.22**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	20.34		
Base rate total	23.71	20,000	4,742.00
Fuel Adjustment	0.00	20,000	-
Ex. Rate Adjustment	0.00	20,000	-
PPA Adjustment	0.00	20,000	-
Energy Cost			**4,742.00**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	113	2,446.88
Subtotal before VAT			**7,188.88**
VAT @15%			1,078.33
Total			**$ 8,267.21**

Change before VAT:	**$4,756**	**66.2%**
Change after VAT:	**$5,469**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D2

Tariff Options? (●) D2 ( ) D1 ( ) B1 ( ) B

Tariff Year: 2008

Customer Name: HOTEL #1

Reduce Reserve? ( ) No (●) Yes

PF Improved? (●) No ( ) Yes

860	**kVA reserve**	604	**kW usage**	338,100	**kWh sales**
710	**kVA usage**	0.850	**power factor**	0.778	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	4.56		
Base rate total	12.20	338,100	41,246.27
Fuel Adjustment	0.00	338,100	-
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	0.00	338,100	-
Energy Cost			**41,246.27**
Customer Charge			**-**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	74.80	710	53,109.11
Subtotal before VAT			**94,355.38**
VAT @15%			14,153.31
Total			**$ 108,508.69**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	18.79		
Base rate total	22.16	338,100	74,922.96
Fuel Adjustment	0.00	338,100	-
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	0.00	338,100	-
Energy Cost			**74,922.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	710	15,442.50
Subtotal before VAT			**90,365.46**
VAT @15%			13,554.82
Total			**$ 103,920.28**

Change before VAT:	**$3,990**	**4.4%**
Change after VAT:	**$4,588**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D2

Tariff Options? (•) D2 ( ) D1 ( ) B1 ( ) B

Tariff Year: 2008

Customer Name: HOTEL #1

Reduce Reserve? ( ) No (•) Yes

PF Improved? (•) No ( ) Yes

860	**kVA reserve**	604	**kW usage**	338,100	**kWh sales**
710	**kVA usage**	0.850	**power factor**	0.778	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	11.51		
Base rate total	19.15	338,100	64,746.15
Fuel Adjustment	1.32	338,100	4,446.69
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	1.87	338,100	6,322.47
Energy Cost			**75,515.31**
Customer Charge			**-**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	61.50	710	43,665.00
Subtotal before VAT			**119,180.31**
VAT @15%			17,877.05
Total			**$ 137,057.36**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	18.79		
Base rate total	22.16	338,100	74,922.96
Fuel Adjustment	0.00	338,100	-
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	0.00	338,100	-
Energy Cost			**74,922.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	710	15,442.50
Subtotal before VAT			**90,365.46**
VAT @15%			13,554.82
Total			**$ 103,920.28**

Change before VAT: $28,815 31.9%
Change after VAT: $33,137

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D2

Tariff Options? (•) D2 ( ) D1 ( ) B1 ( ) B

Tariff Year: 2008

Customer Name: HOTEL #1

Reduce Reserve? ( ) No (•) Yes

860	**kVA reserve**	604	**kW usage**	338,100	**kWh sales**
710	**kVA usage**	0.850	**power factor**	0.778	**Load factor**

PF Improved? (•) No ( ) Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	4.56		
Base rate total	12.20	338,100	41,246.27
Fuel Adjustment	0.00	338,100	-
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	0.00	338,100	-
Energy Cost			**41,246.27**
Customer Charge			**-**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	74.80	710	53,109.11
Subtotal before VAT			**94,355.38**
VAT @15%			14,153.31
Total			**$ 108,508.69**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	18.79		
Base rate total	22.16	338,100	74,922.96
Fuel Adjustment	0.00	338,100	-
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	0.00	338,100	-
Energy Cost			**74,922.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	710	15,442.50
Subtotal before VAT			**90,365.46**
VAT @15%			13,554.82
Total			**$ 103,920.28**

Change before VAT:	**$3,990**	**4.4%**
Change after VAT:	**$4,588**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D2

Tariff Options? (•) D2 ( ) D1 ( ) B1 ( ) B

Tariff Year: 2008

Customer Name: HOTEL #1

Reduce Reserve? ( ) No (•) Yes

860	**kVA reserve**	604	**kW usage**	338,100	**kWh sales**
710	**kVA usage**	0.850	**power factor**	0.778	**Load factor**

PF Improved? (•) No ( ) Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	11.51		
Base rate total	19.15	338,100	64,746.15
Fuel Adjustment	1.32	338,100	4,446.69
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	1.87	338,100	6,322.47
Energy Cost			**75,515.31**
Customer Charge			**-**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	61.50	710	43,665.00
Subtotal before VAT			**119,180.31**
VAT @15%			17,877.05
Total			**$ 137,057.36**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	18.79		
Base rate total	22.16	338,100	74,922.96
Fuel Adjustment	0.00	338,100	-
Ex. Rate Adjustment	0.00	338,100	-
PPA Adjustment	0.00	338,100	-
Energy Cost			**74,922.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	21.75	710	15,442.50
Subtotal before VAT			**90,365.46**
VAT @15%			13,554.82
Total			**$103,920.28**

Change before VAT: $28,815 31.9%
Change after VAT: $33,137

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D3

Tariff Year: 2008
Customer Name: E.W.M.S.C.A

Reduce Reserve? (•) No ( ) Yes
PF Improved? (•) No ( ) Yes

6,200	kVA reserve	2,672	kW usage	1,353,008	kWh sales
3,332	kVA usage	0.802	power factor	0.703	Load factor

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	4.13		
Base rate total	11.77	1,353,008	159,251.56
Fuel Adjustment	0.00	1,353,008	-
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	0.00	1,353,008	-
Energy Cost			**159,251.56**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	85.09	4,650	395,651.45
Subtotal before VAT			**554,903.01**
VAT @15%			83,235.45
Total			**$ 638,138.46**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	1,353,008	187,526.96
Fuel Adjustment	0.00	1,353,008	-
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	0.00	1,353,008	-
Energy Cost			**187,526.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	4,650	121,272.00
Subtotal before VAT			**308,798.96**
VAT @15%			46,319.84
Total			**$ 355,118.80**

Change before VAT:	**$246,104.06**	**79.7%**
Change after VAT:	**$283,019.67**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D3

Tariff Year: 2008

Customer Name: E.W.M.S.C.A

Reduce Reserve? (●) No ( ) Yes

PF Improved? (●) No ( ) Yes

6,200	**kVA reserve**	2,672	**kW usage**	1,353,008	**kWh sales**
3,332	**kVA usage**	0.802	**power factor**	0.703	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	4.76		
Base rate total	12.40	1,353,008	167,773.03
Fuel Adjustment	1.32	1,353,008	17,794.77
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	1.87	1,353,008	25,301.26
Energy Cost			**210,869.05**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	55.00	4,650	255,750.00
Subtotal before VAT			**466,619.05**
VAT @15%			69,992.86
Total			**$ 536,611.91**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	1,353,008	187,526.96
Fuel Adjustment	0.00	1,353,008	-
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	0.00	1,353,008	-
Energy Cost			**187,526.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	4,650	121,272.00
Subtotal before VAT			**308,798.96**
VAT @15%			46,319.84
Total			**$ 355,118.80**

Change before VAT:	**$157,820.10**	**51.1%**
Change after VAT:	**$181,493.12**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D3

Tariff Year: 2008

Customer Name: E.W.M.S.C.A

Reduce Reserve? ● No ○ Yes

PF Improved? ● No ○ Yes

6,200	**kVA reserve**	2,672	**kW usage**	1,353,008	**kWh sales**
3,332	**kVA usage**	0.802	**power factor**	0.703	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	4.13		
Base rate total	11.77	1,353,008	159,251.56
Fuel Adjustment	0.00	1,353,008	-
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	0.00	1,353,008	-
Energy Cost			**159,251.56**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	85.09	4,650	395,651.45
Subtotal before VAT			**554,903.01**
VAT @15%			83,235.45
Total			**$ 638,138.46**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	1,353,008	187,526.96
Fuel Adjustment	0.00	1,353,008	-
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	0.00	1,353,008	-
Energy Cost			**187,526.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	4,650	121,272.00
Subtotal before VAT			**308,798.96**
VAT @15%			46,319.84
Total			**$ 355,118.80**

Change before VAT: $246,104.06 79.7%

Change after VAT: $283,019.67

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D3

Tariff Year: 2008

Customer Name: E.W.M.S.C.A

6,200	**kVA reserve**	2,672	**kW usage**	1,353,008	**kWh sales**
3,332	**kVA usage**	0.802	**power factor**	0.703	**Load factor**

Reduce Reserve? ◉ No ○ Yes

PF Improved? ◉ No ○ Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	4.76		
Base rate total	12.40	1,353,008	167,773.03
Fuel Adjustment	1.32	1,353,008	17,794.77
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	1.87	1,353,008	25,301.26
Energy Cost			**210,869.05**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	55.00	4,650	255,750.00
Subtotal before VAT			**466,619.05**
VAT @15%			69,992.86
Total			**$536,611.91**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	1,353,008	187,526.96
Fuel Adjustment	0.00	1,353,008	-
Ex. Rate Adjustment	0.00	1,353,008	-
PPA Adjustment	0.00	1,353,008	-
Energy Cost			**187,526.96**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	4,650	121,272.00
Subtotal before VAT			**308,798.96**
VAT @15%			46,319.84
Total			**$ 355,118.80**

Change before VAT: $157,820.10 51.1%
Change after VAT: $181,493.12

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D4

Tariff Year: 2004

Customer Name: D4 Customer #6

4,500	**kVA reserve**	3,583	**kW usage**	694,016	**kWh sales**
3,981	**kVA usage**	0.950	**power factor**	0.269	**Load factor**

Reduce Reserve? No / Yes (selected: Yes)

PF Improved? No / Yes (selected: Yes)

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	0.48		
Base rate total	8.13	694,016	56,405.90
Fuel Adjustment	0.00	694,016	-
Ex. Rate Adjustment	0.00	694,016	-
PPA Adjustment	0.00	694,016	-
Energy Cost			**56,405.90**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	47.36	3,772	178,624.30
Subtotal before VAT			**235,030.20**
VAT @15%			35,254.53
Total			**$ 270,284.73**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	694,016	96,190.62
Fuel Adjustment	0.00	694,016	-
Ex. Rate Adjustment	0.00	694,016	-
PPA Adjustment	0.00	694,016	-
Energy Cost			**96,190.62**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	3,981	103,831.00
Subtotal before VAT			**200,021.62**
VAT @15%			30,003.24
Total			**$ 230,024.86**

Change before VAT:	**$35,008.58**	**17.5%**
Change after VAT:	**$40,259.87**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D4

Tariff Year: 2004
Customer Name: D4 Customer #6

Reduce Reserve? No / Yes (selected)
PF Improved? No / Yes (selected)

4,500	**kVA reserve**	3,583	**kW usage**	694,016	**kWh sales**
3,981	**kVA usage**	0.950	**power factor**	0.269	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	3.76		
Base rate total	11.40	694,016	79,117.82
Fuel Adjustment	0.00	694,016	-
Ex. Rate Adjustment	0.00	694,016	-
PPA Adjustment	0.52	694,016	3,608.88
Energy Cost			**82,726.71**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	52.00	3,772	196,128.95
Subtotal before VAT			**278,855.65**
VAT @15%			41,828.35
Total			**$ 320,684.00**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	694,016	96,190.62
Fuel Adjustment	0.00	694,016	-
Ex. Rate Adjustment	0.00	694,016	-
PPA Adjustment	0.00	694,016	-
Energy Cost			**96,190.62**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	3,981	103,831.00
Subtotal before VAT			**200,021.62**
VAT @15%			30,003.24
Total			**$ 230,024.86**

Change before VAT: **$78,834.04** **39.4%**
Change after VAT: **$90,659.15**

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D4

Tariff Year: 2004

Customer Name: D4 Customer #6

Reduce Reserve? No / Yes (Yes selected)

PF Improved? No / Yes (Yes selected)

4,500	**kVA reserve**	3,583	**kW usage**	694,016	**kWh sales**
3,981	**kVA usage**	0.950	**power factor**	0.269	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	0.48		
Base rate total	8.13	694,016	56,405.90
Fuel Adjustment	0.00	694,016	-
Ex. Rate Adjustment	0.00	694,016	-
PPA Adjustment	0.00	694,016	-
Energy Cost			**56,405.90**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	47.36	3,772	178,624.30
Subtotal before VAT			**235,030.20**
VAT @15%			35,254.53
Total			**$270,284.73**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	694,016	96,190.62
Fuel Adjustment	0.00	694,016	-
Ex. Rate Adjustment	0.00	694,016	-
PPA Adjustment	0.00	694,016	-
Energy Cost			**96,190.62**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	3,981	103,831.00
Subtotal before VAT			**200,021.62**
VAT @15%			30,003.24
Total			**$230,024.86**

Change before VAT:	**$35,008.58**	**17.5%**
Change after VAT:	**$40,259.87**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D4

Tariff Year: 2004

Customer Name: D4 Customer #6

4,500	**kVA reserve**	3,583	**kW usage**	694,016	**kWh sales**
3,981	**kVA usage**	0.950	**power factor**	0.269	**Load factor**

Reduce Reserve? No / Yes (selected: Yes)

PF Improved? No / Yes (selected: Yes)

Sample Bill - Based on 2004 Rate Application				**Comparison Bill Based on 2003 Tariff**			
Energy Charges	**¢/kWh**	**kWh**	**Cost $**	**Energy Charges**	**¢/kWh**	**kWh**	**Cost $**
Base Rate				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	3.76			- other	10.49		
Base rate total	11.40	694,016	79,117.82	Base rate total	13.86	694,016	96,190.62
Fuel Adjustment	0.00	694,016	-	Fuel Adjustment	0.00	694,016	-
Ex. Rate Adjustment	0.00	694,016	-	Ex. Rate Adjustment	0.00	694,016	-
PPA Adjustment	0.52	694,016	3,608.88	PPA Adjustment	0.00	694,016	-
Energy Cost			**82,726.71**	**Energy Cost**			**96,190.62**
Demand Charges	**$/kVA**	**kVA**	**Cost $**	**Demand Charges**	**$/kVA**	**kVA**	**Cost $**
Base Rate	52.00	3,772	196,128.95	Base Rate	26.08	3,981	103,831.00
Subtotal before VAT			**278,855.65**	**Subtotal before VAT**			**200,021.62**
VAT @15%			41,828.35	VAT @15%			30,003.24
Total			**$ 320,684.00**	**Total**			**$ 230,024.86**

Change before VAT:	**$78,834.04**	**39.4%**
Change after VAT:	**$90,659.15**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D5

Tariff Year: 2008

Customer Name: Ammonia Plant #2

Reduce Reserve? ● No ○ Yes

PF Improved? ● No ○ Yes

10,000	**kVA reserve**	6,669	**kW usage**	3,316,238	**kWh sales**
7,675	**kVA usage**	0.869	**power factor**	0.691	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	0.90		
Base rate total	8.54	3,316,238	283,249.88
Fuel Adjustment	0.00	3,316,238	-
Ex. Rate Adjustment	0.00	3,316,238	-
PPA Adjustment	0.00	3,316,238	-
Energy Cost			**283,249.88**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	34.77	7,675	266,831.63
Subtotal before VAT			**550,081.51**
VAT @15%			82,512.23
Total			**$ 632,593.74**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	3,316,238	459,630.53
Fuel Adjustment	0.00	3,316,238	-
Ex. Rate Adjustment	0.00	3,316,238	-
PPA Adjustment	0.00	3,316,238	-
Energy Cost			**459,630.53**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	7,675	200,159.65
Subtotal before VAT			**659,790.18**
VAT @15%			98,968.53
Total			**$ 758,758.71**

Change before VAT:	**($109,708.67)**	**-16.6%**
Change after VAT:	**($126,164.97)**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D5

Tariff Year: 2008
Customer Name: Ammonia Plant #2

10,000	**kVA reserve**	6,669	**kW usage**	3,316,238	**kWh sales**
7,675	**kVA usage**	0.869	**power factor**	0.691	**Load factor**

Reduce Reserve? ◉ No ○ Yes
PF Improved? ◉ No ○ Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	9.26		
Base rate total	16.90	3,316,238	560,444.15
Fuel Adjustment	1.32	3,316,238	43,615.16
Ex. Rate Adjustment	0.00	3,316,238	-
PPA Adjustment	1.87	3,316,238	62,013.64
Energy Cost			**666,072.95**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	31.00	7,675	237,919.83
Subtotal before VAT			**903,992.78**
VAT @15%			135,598.92
Total			**$1,039,591.70**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	3,316,238	459,630.53
Fuel Adjustment	0.00	3,316,238	-
Ex. Rate Adjustment	0.00	3,316,238	-
PPA Adjustment	0.00	3,316,238	-
Energy Cost			**459,630.53**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	7,675	200,159.65
Subtotal before VAT			**659,790.18**
VAT @15%			98,968.53
Total			**$758,758.71**

Change before VAT:	**$244,202.60**	**37.0%**
Change after VAT:	**$280,832.99**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D5

Tariff Year: 2008

Customer Name: Ammonia Plant #2

10,000	**kVA reserve**	6,669	**kW usage**	3,316,238	**kWh sales**
7,675	**kVA usage**	0.869	**power factor**	0.691	**Load factor**

Reduce Reserve? ◉ No ○ Yes

PF Improved? ◉ No ○ Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	0.90		
Base rate total	8.54	3,316,238	283,249.88
Fuel Adjustment	0.00	3,316,238	-
Ex. Rate Adjustment	0.00	3,316,238	-
PPA Adjustment	0.00	3,316,238	-
Energy Cost			**283,249.88**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	34.77	7,675	266,831.63
Subtotal before VAT			**550,081.51**
VAT @15%			82,512.23
Total			**$ 632,593.74**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	10.49		
Base rate total	13.86	3,316,238	459,630.53
Fuel Adjustment	0.00	3,316,238	-
Ex. Rate Adjustment	0.00	3,316,238	-
PPA Adjustment	0.00	3,316,238	-
Energy Cost			**459,630.53**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	26.08	7,675	200,159.65
Subtotal before VAT			**659,790.18**
VAT @15%			98,968.53
Total			**$758,758.71**

Change before VAT:	**($109,708.67)**	**-16.6%**
Change after VAT:	**($126,164.97)**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-D5

Tariff Year: 2008

Customer Name: Ammonia Plant #2

Reduce Reserve? (•) No ( ) Yes

PF Improved? (•) No ( ) Yes

10,000	**kVA reserve**	6,669	**kW usage**	3,316,238	**kWh sales**
7,675	**kVA usage**	0.869	**power factor**	0.691	**Load factor**

Sample Bill - Based on 2004 Rate Application				**Comparison Bill Based on 2003 Tariff**			
Energy Charges	**¢/kWh**	**kWh**	**Cost $**	**Energy Charges**	**¢/kWh**	**kWh**	**Cost $**
Base Rate				Base Rate			
- fuel	7.64			- fuel	3.37		
- other	9.26			- other	10.49		
Base rate total	16.90	3,316,238	560,444.15	Base rate total	13.86	3,316,238	459,630.53
Fuel Adjustment	1.32	3,316,238	43,615.16	Fuel Adjustment	0.00	3,316,238	-
Ex. Rate Adjustment	0.00	3,316,238	-	Ex. Rate Adjustment	0.00	3,316,238	-
PPA Adjustment	1.87	3,316,238	62,013.64	PPA Adjustment	0.00	3,316,238	-
Energy Cost			**666,072.95**	**Energy Cost**			**459,630.53**
Demand Charges	**$/kVA**	**kVA**	**Cost $**	**Demand Charges**	**$/kVA**	**kVA**	**Cost $**
Base Rate	31.00	7,675	237,919.83	Base Rate	26.08	7,675	200,159.65
Subtotal before VAT			**903,992.78**	**Subtotal before VAT**			**659,790.18**
VAT @15%			135,598.92	VAT @15%			98,968.53
Total			**$1,039,591.70**	**Total**			**$758,758.71**

Change before VAT:	**$244,202.60**	**37.0%**
Change after VAT:	**$280,832.99**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E1

Tariff Year: 2008 **Customer Name:** Petrotrin

32,000	**kVA reserve**	29,554	**kW usage**	17,492,312	**kWh sales**
32,838	**kVA usage**	0.900	**power factor**	0.822	**Load factor**

Reduce Reserve? (•) No ( ) Yes

PF Improved? (•) No ( ) Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	0.83		
Base rate total	8.47	17,492,312	1,481,627.76
Fuel Adjustment	0.00	17,492,312	-
Ex. Rate Adjustment	0.00	17,492,312	-
PPA Adjustment	0.00	17,492,312	-
Energy Cost			**1,481,627.76**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	57.82	32,838	1,898,803.79
Subtotal before VAT			**3,380,431.55**
VAT @15%			507,064.73
Total			**$ 3,887,496.28**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	17,492,312	2,291,492.82
Fuel Adjustment	0.00	17,492,312	-
Ex. Rate Adjustment	0.00	17,492,312	-
PPA Adjustment	0.00	17,492,312	-
Energy Cost			**2,291,492.82**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	32,838	774,974.83
Subtotal before VAT			**3,066,467.65**
VAT @15%			459,970.15
Total			**$ 3,526,437.80**

Change before VAT:	**$313,963.90**	**10.2%**
Change after VAT:	**$361,058.48**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E1

Tariff Year: 2008

Customer Name: Petrotrin

Reduce Reserve? (•) No ( ) Yes

PF Improved? (•) No ( ) Yes

32,000	**kVA reserve**	29,554	**kW usage**	17,492,312	**kWh sales**
32,838	**kVA usage**	0.900	**power factor**	0.822	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	3.86		
Base rate total	11.50	17,492,312	2,011,615.83
Fuel Adjustment	1.32	17,492,312	230,058.88
Ex. Rate Adjustment	0.00	17,492,312	-
PPA Adjustment	1.87	17,492,312	327,106.23
Energy Cost			**2,568,780.94**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	53.00	32,838	1,740,409.58
Subtotal before VAT			**4,309,190.52**
VAT @15%			646,378.58
Total			**$ 4,955,569.10**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	17,492,312	2,291,492.82
Fuel Adjustment	0.00	17,492,312	-
Ex. Rate Adjustment	0.00	17,492,312	-
PPA Adjustment	0.00	17,492,312	-
Energy Cost			**2,291,492.82**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	32,838	774,974.83
Subtotal before VAT			**3,066,467.65**
VAT @15%			459,970.15
Total			**$ 3,526,437.80**

Change before VAT:	**$1,242,722.87**	**40.5%**
Change after VAT:	**$1,429,131.30**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E1

Tariff Year: 2008

Customer Name: Petrotrin

32,000	**kVA reserve**	29,554	**kW usage**	17,492,312	**kWh sales**
32,838	**kVA usage**	0.900	**power factor**	0.822	**Load factor**

Reduce Reserve? No (selected) Yes

PF Improved? No (selected) Yes

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	0.83		
Base rate total	8.47	17,492,312	1,481,627.76
Fuel Adjustment	0.00	17,492,312	-
Ex. Rate Adjustment	0.00	17,492,312	-
PPA Adjustment	0.00	17,492,312	-
Energy Cost			**1,481,627.76**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	57.82	32,838	1,898,803.79
Subtotal before VAT			**3,380,431.55**
VAT @15%			507,064.73
Total			**$ 3,887,496.28**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	17,492,312	2,291,492.82
Fuel Adjustment	0.00	17,492,312	-
Ex. Rate Adjustmen	0.00	17,492,312	-
PPA Adjustment	0.00	17,492,312	-
Energy Cost			**2,291,492.82**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	32,838	774,974.83
Subtotal before VAT			**3,066,467.65**
VAT @15%			459,970.15
Total			**$ 3,526,437.80**

Change before VAT:	**$313,963.90**	**10.2%**
Change after VAT:	**$361,058.48**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E1

Tariff Year: 2008
Customer Name: Petrotrin

Reduce Reserve? (•) No ( ) Yes
PF Improved? (•) No ( ) Yes

32,000	**kVA reserve**	29,554	**kW usage**	17,492,312	**kWh sales**
32,838	**kVA usage**	0.900	**power factor**	0.822	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	3.86		
Base rate total	11.50	17,492,312	2,011,615.83
Fuel Adjustment	1.32	17,492,312	230,058.88
Ex. Rate Adjustment	0.00	17,492,312	-
PPA Adjustment	1.87	17,492,312	327,106.23
Energy Cost			**2,568,780.94**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	53.00	32,838	1,740,409.58
Subtotal before VAT			**4,309,190.52**
VAT @15%			646,378.58
Total			**$ 4,955,569.10**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	17,492,312	2,291,492.82
Fuel Adjustment	0.00	17,492,312	-
Ex. Rate Adjustment	0.00	17,492,312	-
PPA Adjustment	0.00	17,492,312	-
Energy Cost			**2,291,492.82**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	32,838	774,974.83
Subtotal before VAT			**3,066,467.65**
VAT @15%			459,970.15
Total			**$3,526,437.80**

Change before VAT:	**$1,242,722.87**	**40.5%**
Change after VAT:	**$1,429,131.30**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E5

Tariff Year: 2008
Customer Name: Ispat

Reduce Reserve? No / Yes
PF Improved? No / Yes

150,000	**kVA reserve**	208,332	**kW usage**	100,397,580	**kWh sales**
231,480	**kVA usage**	0.900	**power factor**	0.669	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	0.85		
Base rate total	8.50	100,397,580	8,529,520.59
Fuel Adjustment	0.00	100,397,580	-
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	0.00	100,397,580	-
Energy Cost			**8,529,520.59**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	52.79	231,480	12,218,865.44
Subtotal before VAT			**20,748,386.03**
VAT @15%			3,112,257.90
Total			**$ 23,860,643.93**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	100,397,580	13,152,082.98
Fuel Adjustment	0.00	100,397,580	-
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	0.00	100,397,580	-
Energy Cost			**13,152,082.98**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	231,480	5,462,928.00
Subtotal before VAT			**18,615,010.98**
VAT @15%			2,792,251.65
Total			**$ 21,407,262.63**

Change before VAT:	**$2,133,375.05**	**11.5%**
Change after VAT:	**$2,453,381.30**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E5

Tariff Year: 2008

Customer Name: Ispat

Reduce Reserve? (•) No ( ) Yes

PF Improved? (•) No ( ) Yes

150,000	**kVA reserve**	208,332	**kW usage**	100,397,580	**kWh sales**
231,480	**kVA usage**	0.900	**power factor**	0.669	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	2.56		
Base rate total	10.20	100,397,580	10,240,553.16
Fuel Adjustment	1.32	100,397,580	1,320,428.97
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	1.87	100,397,580	1,877,434.75
Energy Cost			**13,438,416.88**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	48.00	231,480	11,111,040.00
Subtotal before VAT			**24,549,456.88**
VAT @15%			3,682,418.53
Total			**$ 28,231,875.41**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	100,397,580	13,152,082.98
Fuel Adjustment	0.00	100,397,580	-
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	0.00	100,397,580	-
Energy Cost			**13,152,082.98**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	231,480	5,462,928.00
Subtotal before VAT			**18,615,010.98**
VAT @15%			2,792,251.65
Total			**$ 21,407,262.63**

Change before VAT:	**$5,934,445.90**	**31.9%**
Change after VAT:	**$6,824,612.78**	

APPENDIX 22

SAMPLE BILLS (TRUE COST)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E5

Tariff Year: 2008
Customer Name: Ispat

Reduce Reserve? ● No ○ Yes
PF Improved? ● No ○ Yes

150,000	**kVA reserve**	208,332	**kW usage**	100,397,580	**kWh sales**
231,480	**kVA usage**	0.900	**power factor**	0.669	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	7.64		
- other	0.85		
Base rate total	8.50	100,397,580	8,529,520.59
Fuel Adjustment	0.00	100,397,580	-
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	0.00	100,397,580	-
Energy Cost			**8,529,520.59**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	52.79	231,480	12,218,865.44
Subtotal before VAT			**20,748,386.03**
VAT @15%			3,112,257.90
Total			**$ 23,860,643.93**

Comparison Bill Based on 2003 Tariff

Energy Charges	**¢/kWh**	**kWh**	**Cost $**
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	100,397,580	13,152,082.98
Fuel Adjustment	0.00	100,397,580	-
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	0.00	100,397,580	-
Energy Cost			**13,152,082.98**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	231,480	5,462,928.00
Subtotal before VAT			**18,615,010.98**
VAT @15%			2,792,251.65
Total			**$ 21,407,262.63**

Change before VAT:	**$2,133,375.05**	**11.5%**
Change after VAT:	**$2,453,381.30**	

APPENDIX 22

SAMPLE BILLS (CROSS-SUBSIDISATION)

Trinidad and Tobago Electricity Commission
63 Frederick Street, Port of Spain
Rate-E5

Tariff Year: 2008
Customer Name: Ispat

Reduce Reserve? ◉ No ○ Yes
PF Improved? ◉ No ○ Yes

150,000	**kVA reserve**	208,332	**kW usage**	100,397,580	**kWh sales**
231,480	**kVA usage**	0.900	**power factor**	0.669	**Load factor**

Sample Bill - Based on 2004 Rate Application

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	7.64		
- other	2.56		
Base rate total	10.20	100,397,580	10,240,553.16
Fuel Adjustment	1.32	100,397,580	1,320,428.97
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	1.87	100,397,580	1,877,434.75
Energy Cost			**13,438,416.88**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	48.00	231,480	11,111,040.00
Subtotal before VAT			**24,549,456.88**
VAT @15%			3,682,418.53
Total			**$ 28,231,875.41**

Comparison Bill Based on 2003 Tariff

Energy Charges	¢/kWh	kWh	Cost $
Base Rate			
- fuel	3.37		
- other	9.73		
Base rate total	13.10	100,397,580	13,152,082.98
Fuel Adjustment	0.00	100,397,580	-
Ex. Rate Adjustment	0.00	100,397,580	-
PPA Adjustment	0.00	100,397,580	-
Energy Cost			**13,152,082.98**
Demand Charges	**$/kVA**	**kVA**	**Cost $**
Base Rate	23.60	231,480	5,462,928.00
Subtotal before VAT			**18,615,010.98**
VAT @15%			2,792,251.65
Total			**$21,407,262.63**

Change before VAT:	**$5,934,445.90**	**31.9%**
Change after VAT:	**$6,824,612.78**	

APPENDIX 23

Trinidad and Tobago Electricity Commission

PROPOSED CHARACTER OF SERVICE RULES FOR NEW AND EXISTING RATE TARIFFS

As a prelude to T&TEC's application to the *Regulated Industries Commission* (RIC) for a new rate structure, the character of service rules of existing and proposed rate tariffs were reviewed. The following gives a summary of the proposals, the details of which are included in the Appendix.

PROPOSED CHARACTER OF SERVICE

Rates A (Residential)
There is to be no change to the character of service of the Rate A tariff.

A three-tiered tariff will be introduced and the minimum bill for this group will now be the Customer Charge.

Rates B (Commercial)
The Rate B supply voltage options have been expanded to include the 6.6kV and 12kV voltage levels. The minimum bill for this group is to be the Customer Charge.

Rate B1 (Commercial and small Industrial Demands)
A new rate tariff, Rate B1, is to be introduced. This proposed rate class will cater for commercial and small industrial customers with demands in the range 50kVA to 350kVA and nominally low load factors (0.30 or less). The supply voltage covers the entire range of the Commission's standard distribution voltages (115V to 33kV). In all cases however, the choice of supply voltage will depend on the specifics of the location and will be at the discretion and operating convenience of the Commission.

Customers in this rate class will be billed monthly. Customers will be fitted with energy (kWh) and demand (kVA) type meters but will be billed only on their energy consumption. Their kVA demand will be monitored and a rate change effected to a new rate class whenever their monthly maximum demand exceeds 350kVA for three (3) consecutive months. The customer will remain in the new rate class for a minimum of six (6) months. Should the customer's maximum demand subsequently fall below the minimum kVA limit of the new rate group, the customer may request to be reassigned to a new rate group.

The minimum bill for Rate B1 will be based on 5,000kWh of billed energy consumption.

Rate D1 and D2 (Commercial and Industrial)
Character of service rules for the D1 (small industrial demands) and D2 (medium industrial demands) customer groups have been amended to offer greater supply voltage options. These options will make a customer's kVA maximum demand the primary basis for assignment to a particular rate class. The kVA maximum demand ranges for these groups remain unchanged:

above 50kVA and not exceeding 350kVA	-	Rate D1
above 350kVA and not exceeding 4,000kVA	-	Rate D2

It is clear from the above that customers in the kVA range 50kVA to 350kVA have a choice as to which tariff would be more economical for them.

The supply voltages available for the Rate D1 class cover the entire range of the Commission's standard distribution voltages (115V to 33kV). For the Rate D2 group, the higher distribution voltages of 6.6kV (where applicable), 12kV and 33kV, are the only offered supply voltages. In all cases however, the choice of supply voltage will depend on the specifics of the location and will be at the discretion and operating convenience of the Commission.

Rate D1 andD2 customers will continue to be billed monthly and will pay both an energy charge (¢/kWh) and a kVA demand charge ($/kVA). The energy billing will be based on actual kWh consumption while the demand billing will be based on the customer's ***Billing kVA Demand***. The Billing kVA Demand for each customer in a month is defined as the highest of:

- the metered kVA demand in the month
- 75% of the reserve capacity of the customer, or
- the minimum kVA limit of the tariff class or group

The minimum monthly bill for a rate D1 and D2 customer will therefore be the demand billing.

Rate D3, D4 and D5 (Large Industrial)
Two new rate classes, Rates D4 and D5, have been introduced in the large industrial demand category. The kVA maximum demand of all three groups covers the range 4,001kVA to 25,000kVA as currently exists for the D3 group.

Rate D3 will now cater for large industrial customers supplied at distribution level voltages – 6.6kV (where available), 12kV and 33kV. The introduction of the two lower voltage levels will give both customers and the Commission greater options when designing their electrical systems and will generally minimize the total cost to both parties. In all cases however, the choice of supply voltage will depend on the specifics of the location and will be at the discretion and operating convenience of the Commission.

The Rate D4 class caters for those large industrial concerns, connected directly to the transmission system at voltage levels 66kV and above. Rate D5 caters for those large industrial concerns connected to the Commission's transmission system at voltages of 66kV and above that possess an independent source of electrical power and request a backup supply from the Commission.

As with D1 and D2 customers, D3, D4 and D5 customers will continue to be billed monthly and will pay both an energy charge (¢/kWh) and a kVA demand charge ($/kVA).

Rate E (very large Industrial Demands)
The very large industrial demand rate class, Rate E is to be subdivided into five levels – Rates E1, E2, E3, E4 and E5. The supply voltages available for these rate classes are 66kV and above with a minimum kVA demand of 25,000kVA. This will permit distinctions in the cost of service between customers to be made based on the level of average monthly energy consumption. The limits of average monthly energy consumption are as follows:

up to 25,000kWh per month	-	Rate E1
above 25,000kWh to 50,000kWh per month	-	Rate E2
above 50,000kWh to 75,000kWh per month	-	Rate E3
above 75,000kWh to 100,000kWh per month	-	Rate E4
in excess of 100,000kWh per month	-	Rate E5

The minimum bill for Rates E1, E2, E3, E4 and E5 is class in a demand charge based on 75% of the reserve capacity of the customer or on the minimum kVA of the class, whichever is higher.

Rate S (Street Lighting and Facilities)
The existing street lighting rate tariffs, Rate S1, S2 and S3, are to be retained with the luminaries and fitting types modified to include only the Commissions current standard types. Customers currently billed under Rates S1 or S2 and a classification with non-standard fittings are to be reassigned to a classification with the equivalent fittings.

The Characters of Service for the various rate classes are detailed in Schedule A below

It is emphasized that a Rate class is to be assigned to a customer based solely on the discretion of the Commission and on the availability of supply at the appropriate voltage level. Reassignment to another rate class is to be effected automatically after the maximum demand exceeds the minimum demand value for that class for three (3) consecutive periods.

The customer is to be notified of the excess demand used and the intent to reclassify, on each of the three monthly bills prior to the reclassification.

While it is accepted that the above proposals will provide for maximum recovery of capital costs, it is to be noted that some situations may occur where a Non-Refundable Capital Contribution (NRCC) would be required to recover the capital costs expended in those unusual situations.

CHARACTER OF SERVICE DETAIL

Rate A (Residential)

Availability

All domestic and household electricity supplies for use by one family living in one residence supplied from one meter.

Character of Service

60 hertz, alternating current, single phase, 2-wire or 3-wire, 115V or 230V. A three-phase supply may be made available upon application, at the discretion of the Commission.

Energy Charge

All kWh consumed over a two (2) month period will be billed as follows:

2-monthly Energy Usage	2004	2005	2006	2007	2008
			¢/kWh		
First 500kWh	21.45	21.70	22.20	22.70	23.20
Next 1000kWh	31.00	31.25	31.75	32.25	32.75
Above 1500kWh	44.50	44.75	45.00	45.25	45.50

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 2-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Customer Charge

This fixed amount is billed every two months, regardless of how much electricity is used, to cover the costs of your service and meter, and the administrative costs related to servicing your account. The 2-monthly customer charge is as follows:

2-monthly Customer Charge	2004	2005	2006	2007	2008
	$4.00	$5.00	$6.00	$8.00	$10.00

Minimum Bill

The minimum bill shall be $10.00 for a 2-month billing period or any part thereof.

Rate B (Commercial)

Availability

Electricity supply, for purposes other than domestic and household, in a single installation supplied from one meter.

Character of Service

An alternating current supply at 60 hertz, with a maximum demand of 50kVA. The supply voltage shall be single phase, 3-wire, 115V or 230V; three phase, 4-wire, 115/230V or 230/400V; three phase 6.6kV or 12kV depending on locality and on the operating convenience of the Commission.

Energy Charge

All kWh consumed over a two (2) month period will be billed as follows:

2-monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	31.35	31.60	32.10	32.60	33.10

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 2-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Customer Charge

This fixed amount is billed every two months, regardless of how much electricity is used, to cover the costs of your service and meter, and the administrative costs related to servicing your account. The 2-monthly customer charge is as follows:

2-monthly Customer Charge	2004	2005	2006	2007	2008
	$40.00	$42.00	$44.00	$46.00	$48.00

Minimum Bill

The minimum bill for a 2-month period shall be the 2-monthly customer charge.

Rate B1 (Large Commercial)

Availability

Three phase electricity supply for commercial and industrial purposes.

Character of Service

Three phase 60 hertz, alternating current for loads with a maximum demand greater than 50kVA and not exceeding 350kVA. The supply voltage shall be 4-wire, 115/230V, 230/400; 6.6kV, 12kV or 33kV, depending on locality and on the operating convenience of the Commission.

The maximum demand shall be monitored and once it exceeds 350kVA for three (3) consecutive billing periods, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
	¢/kWh				
All kWh units	41.40	41.90	42.40	42.90	43.40

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Minimum Bill

Customers shall be billed for a minimum of 5000kWh per month or part thereof.

Rate D1 (Small Industrial)

Availability

Three phase electricity supply for commercial and industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current for loads with a maximum demand greater than 50kVA and not exceeding 350kVA. The supply voltage shall be 4-wire, 115/230V, 230/400V; 6.6kV, 12kV or 33kV depending on locality and on the operating convenience of the Commission.

Once the maximum demand either falls below 50kVA or exceeds 350kVA for three (3) consecutive billing periods, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
	¢/kWh				
All kWh units	19.10	19.60	20.10	20.60	21.10

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 50kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	**2004**	**2005**	**2006**	**2007**	**2008**
			$/kVA		
All Billed kVA	$62.00	$62.25	$62.50	$62.75	$63.00

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate D2 (Medium Industrial)

Availability

Three phase, high voltage supply for industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current for loads with a maximum demand greater than 350kVA and not exceeding 4,000kVA at 6.6kV, 12kV, 33kV or 66kV depending on locality and on the operating convenience of the Commission.

Once the maximum demand either falls below 350kVA or exceeds 4,000kVA for three (3) consecutive billing periods, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	18.15	18.40	18.65	18.90	19.15

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.
   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 350kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	**2004**	**2005**	**2006**	**2007**	**2008**
			$/kVA		
All Billed kVA	$60.50	$60.75	$61.00	$61.25	$61.50

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate D3 (Large Industrial)

Availability

Three phase, high voltage supply for industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current for loads with a maximum demand greater than 4,000kVA and not exceeding 25,000kVA at 6.6kV, 12kV or 33kV depending on locality and on the operating convenience of the Commission.

Once the maximum demand either falls below 4,000kVA or exceeds 25,000kVA for three (3) consecutive billing periods, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	11.40	11.65	11.90	12.15	12.40

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 4,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	2004	2005	2006	2007	2008
			$/kVA		
All Billed kVA	$54.00	$54.25	$54.50	$54.75	$55.00

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate D4 (Large Industrial)

Availability

Three phase, high voltage supply for industrial purposes. This class does not include customers receiving a standby supply from the Commission.

Character of Service

Three phase, 60 hertz, alternating current for loads with a maximum demand greater than 4,000kVA and not exceeding 25,000kVA, at 66kV or 132kV depending on locality and on the operating convenience of the Commission.

Once the maximum demand either falls below 4,000kVA or exceeds 25,000kVA for three (3) consecutive billing periods, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	11.40	11.65	11.90	12.15	12.40

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 4,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	2004	2005	2006	2007	2008
			$/kVA		
All Billed kVA	$52.00	$52.25	$52.50	$52.75	$53.00

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate D5 (Large Industrial – Standby)

Availability

Three phase, high voltage supply for customers who own, operate and use an independent source of electrical supply and request a standby supply from the Commission.

Character of Service

Three phase, 60 hertz, alternating current for loads with a maximum demand greater than 4,000kVA at 66kV or 132kV depending on locality and on the operating convenience of the Commission.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	**2004**	**2005**	**2006**	**2007**	**2008**
			¢/kWh		
All kWh units	15.90	16.15	16.40	16.65	16.90

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 4,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	2004	2005	2006	2007	2008
			$/kVA		
All Billed kVA	$30.00	$30.25	$30.50	$30.75	$31.00

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate E1 (Very Large Load)

Availability

Three phase, high voltage supply for industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current at 66kV, 132kV and above for load demands in excess of 25,000kVA with an energy usage of up to 25,000kWh per month. The supply voltage will depend on locality and on the operating convenience of the Commission.

Once the maximum demand is less than or equal to 25,000kVA for three (3) consecutive billing periods or the average monthly energy consumption over a six-month period exceeds 25,000kWh, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	10.500	10.750	11.000	11.250	11.500

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 25,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	**2004**	**2005**	**2006**	**2007**	**2008**
			$/kVA		
All Billed kVA	$51.00	$51.50	$52.00	$52.50	$53.00

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate E2 (Very Large Load)

Availability

Three phase, high voltage supply for industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current at 66kV, 132kV and above for load demands in excess of 25,000kVA with an energy usage in excess of 25,000kWh per month and not exceeding 50,000kWh per month. The supply voltage will depend on locality and on the operating convenience of the Commission.

Once the maximum demand is less than or equal to 25,000kVA for three (3) consecutive billing periods or the average monthly energy consumption over a six-month period falls outside of the range specified above, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	10.175	10.425	10.675	10.925	11.175

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 25,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	2004	2005	2006	2007	2008
			$/kVA		
All Billed kVA	$49.75	$50.25	$50.75	$51.25	$51.75

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate E3 (Very Large Industrial)

Availability

Three phase, high voltage supply for industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current at 66kV, 132kV and above for load demands in excess of 25,000kVA with an energy usage in excess of 50,000kWh per month and not exceeding 75,000kWh per month. The supply voltage will depend on locality and on the operating convenience of the Commission.

Once the maximum demand is less than or equal to 25,000kVA for three (3) consecutive billing periods or the average monthly energy consumption over a six-month period falls outside of the range specified above, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	9.850	10.100	10.350	10.600	10.850

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer’s request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer’s highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 25,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	2004	2005	2006	2007	2008
			$/kVA		
All Billed kVA	$48.50	$49.00	$49.50	$50.00	$50.50

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate E4 (Very Large Industrial)

Availability

Three phase, high voltage supply for industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current at 66kV, 132kV and above for load demands in excess of 25,000kVA with an energy usage in excess of 75,000kWh per month and not exceeding 100,000kWh per month. The supply voltage will depend on locality and on the operating convenience of the Commission.

Once the maximum demand is less than or equal to 25,000kVA for three (3) consecutive billing periods or the average monthly energy consumption over a six-month period falls outside of the range specified above, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	**2004**	**2005**	**2006**	**2007**	**2008**
			¢/kWh		
All kWh units	9.525	9.775	10.025	10.275	10.525

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer’s request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer’s highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 25,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	**2004**	**2005**	**2006**	**2007**	**2008**
			$/kVA		
All Billed kVA	$47.25	$47.75	$48.25	$48.75	$49.25

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate E5 (Very Large Industrial)

Availability

Three phase, high voltage supply for industrial purposes.

Character of Service

Three phase, 60 hertz, alternating current at 66kV, 132kV and above for load demands in excess of 25,000kVA with an energy usage in excess of 100,000kWh per month. The supply voltage will depend on locality and on the operating convenience of the Commission.

Once the maximum demand is less than or equal to 25,000kVA for three (3) consecutive billing periods or the average monthly energy consumption over a six-month period falls outside of the range specified above, the customer will be automatically transferred to an appropriate tariff and all usage will be billed at the applicable rate and under the applicable conditions of that tariff, for a period of not less than six (6) months.

Energy Charge

All kWh consumed over a one (1) month period will be billed as follows:

Monthly Energy Usage Charge	2004	2005	2006	2007	2008
			¢/kWh		
All kWh units	9.200	9.450	9.700	9.950	10.200

Other Energy Charges

The following charges that are described in *Electricity Tariff Adjustment Charges*, shall be applied to each kWh consumed during a 1-month billing period.

- Fuel Adjustment Charge (¢/kWh)
- Exchange Rate Adjustment Charge (¢/kWh)
- Purchase Power Adjustment Charge (¢/kWh)

Reserve Capacity

The Commission will reserve at the customer's request a declared Transmission and Distribution Capacity. This *Reserve Capacity* will be equal to the customer's highest expected monthly kVA demand.

Billed Maximum Demand

The *Billed Maximum Demand* shall be the greater of the following:

1. The *Metered Maximum Demand* in the month which shall be the average kVA load during the 15-minute period of greatest use as indicated by the Commission's meter or at the Commission's option as indicated by tests from time to time.

   In cases where demand is intermittent or subject to violent fluctuations, the Commission may establish the Metered Maximum Demand on the basis of a shorter interval of measurement, or the kVA of transformer capacity required to serve the customer's load or may assess the Metered Maximum Demand on the basis of installed capacity.

2. 75% of the declared Reserved Capacity to a minimum of 25,000kVA.

Maximum Demand Charge

The monthly Maximum Demand Charge is computed by applying the following kVA demand rates to every kVA of Billed Maximum Demand:

Monthly kVA Demand Rate	**2004**	**2005**	**2006**	**2007**	**2008**
			$/kVA		
All Billed kVA	$46.00	$46.50	$47.00	$47.50	$48.00

Minimum Bill

The minimum monthly bill shall be the Maximum Demand Charge.

Rate S1

Availability

For service including energy and maintenance supplied to light installations for the purpose of street, highway and safety lighting of thoroughfares, bridges, parks and other approved locations. The Commission will furnish, install and own the necessary poles, overhead wiring and circuits and fitting. The cost of fittings shall be borne by the Commission.

Character of Service

Usage	Classification	Fitting Type
Highways 50-80 K.P.H.	1	1000W H.P. Sodium
Highways 50-80 K.P.H.	2	310 or 250W H.P. Sodium
Main Routes 50 K.P.H.	3	150-250W H.P. Sodium
Secondary Routes Local Routes & Walkways	4	70W-150W H.P. Sodium

The hours of lighting shall be approximately sunset of one day to sunrise of the next day.

Energy Charge

Rate - Category	2004	2005	2006	2007	2008
			$/year		
S1-1	1003.63	1,030.73	1064.63	1,098.54	1,132.45
S1-2	672.34	690.49	713.20	735.91	758.62
S1-3	487.20	500.35	516.28	532.72	549.16
S1-4	438.48	450.32	465.13	479.94	494.75

Rate S2

Availability

For service including energy and maintenance supplied to light installations for the purpose of street, highway and safety lighting of thoroughfares, bridges, parks and other approved locations. The Commission will furnish, install and own the necessary poles, overhead wiring and circuits and fitting. The cost of fittings shall be borne by the customer.

Character of Service

Usage	Classification	Fitting Type
Highways 50-80 K.P.H.	1	1000W H.P. Sodium
Highways 50-80 K.P.H.	2	310 or 250W H.P. Sodium
Main Routes 50 K.P.H.	3	150-250W H.P. Sodium
Secondary Routes Local Routes & Walkways	4	70W-150W H.P. Sodium

The hours of lighting shall be approximately sunset of one day to sunrise of the next day.

Energy Charge

Rate - Category	2004	2005	2006	2007	2008
	$/year				
S2-2	535.92	550.39	568.49	586.59	604.69
S2-3	409.25	420.30	434.13	447.96	461.79
S2-4	331.30	340.25	351.44	362.63	373

Rate S3

Availability

For energy supplied to traffic light installations for the purpose of controlling traffic along public thoroughfares.

The customer will furnish, install, own and maintain the necessary poles, fittings and circuit wiring to these lamps.

Energy Charge

Rate - Category	2004	2005	2006	2007	2008
	$/year				
S3	214.37	220.16	227.40	234.64	241.88

Electricity Tariff Adjustment Charges

Fuel Charge Adjustment

This charge allows for the partial recovery of the cost of fuel used in the production and delivery of electricity that is over and above a base value approved by the Regulated Industries Commission.

Exchange Rate Adjustment

This charge adjusts for changes in the cost of foreign inputs resulting from movements in the value of the Trinidad and Tobago dollar relative to the United States dollar subsequent to Order No. 80 of 1992 of the Public Utilities Commission. It is applied in accordance with a formula approved by the Regulated Industries Commission.

Purchased Power Adjustment Charge

This charge recovers the escalating cost of purchased power from contracted suppliers in excess of a base value approved by the Regulated Industries Commission.

APPENDIX 24A

OLADE REPORT

COMPARATIVE ELECTRICITY PRICES - JUNE 2002

COUNTRY	NATIONAL CURRENCY (N.C.)	EXCHANGE RATE N.C./US$	DOMESTIC FUELS (US$GALLON)						L.P.G. US$kg	ELECTRICITY (US cent/kWh)		
			REGULAR GASOLINE	PREMIUM GASOLINE	DIESEL OIL	HOUSEHOLD KEROSENE	JET FUEL	FUEL OIL		RESIDENTIAL	COMMERCIAL	INDUSTRIAL
Grenada	Grenadian Dollar	2.70	n/a	2.03	1.54	1.14	n/d	n/d	0.98	22.14	23.38	18.77
Barbados	Barbadian Dollar	2.01	n/a	2.50	2.02	1.19	0.40	0.59	1.25	20.41	21.37	20.35
Suriname	Florin	401.00	n/a	2.11	1.55	1.36	1.36	0.25	0.72	17.08	17.30	13.13
Jamaica	Jamaican Dollar	48.48	1.86	1.97	1.67	1.55	1.15	0.63	0.65	13.06	11.80	10.14
Cuba	Peso Cubano	1.00	1.51	1.89	1.03	0.32	1.05	0.61	0.24	12.57	10.04	7.63
El Salvador	Colon Salvador	8.75	2.25	2.31	1.78	1.48	0.89	1.23	0.39	12.31	13.56	13.56
Panama	Balboa	1.00	1.64	1.70	1.25	0.99	1.00	0.75	0.63	12.08	11.76	9.90
Nicaragua	Corboda de Oro	14.21	1.97	2.06	1.56	1.57	0.35	0.35	0.60	11.22	13.77	10.98
Uruguay	Peso Uruguaya	17.81	3.36	3.78	1.59	1.79	1.36	0.56	0.67	11.19	9.76	5.54
Peru	Nuevo Sol	3.51	2.23	2.85	1.83	1.66	n/d	0.85	0.77	9.32	6.27	5.93
Haiti	Gourde	27.28	1.69	2.05	1.12	0.95	0.95	0.44	0.50	9.26	13.66	13.07
Brasil	Real	2.84	2.28	2.39	1.30	0.72	0.93	0.50	0.89	9.00	7.56	3.83
Ecuador	Dolar	1.00	1.12	1.46	0.90	n/a	1.08	0.53	0.11	8.70	8.60	8.14
Rep. Dominicana	Peso Dominicano	17.86	2.02	2.32	1.21	1.26	1.04	0.96	0.43	8.15	8.25	9.74
Chile	Peso Chileno	697.62	2.07	2.09	1.26	1.44	0.99	0.84	0.66	8.09	7.74	5.38
Guatemala	Quetzel	7.91	1.78	1.82	1.22	1.36	1.12	0.89	0.47	7.87	6.18	7.41
Columbia	Peso Colombiano	2,291.70	1.47	1.80	1.03	0.93	0.86	0.62	0.34	7.67	6.77	6.84
Mexico	Nuevo Peso	10.00	n/a	2.42	1.80	n/a	0.77	0.65	0.55	7.58	13.03	17.14
Honduras	Lempira	16.43	2.33	2.45	1.57	1.31	0.86	0.97	0.56	7.12	10.05	5.87
Costa Rica	Colon	358.35	2.16	2.25	1.57	1.54	1.47	0.59	0.72	6.47	9.38	7.41
Guyana	Guayanese Dollar	190.75	n/a	1.18	1.02	0.86	0.86	0.69	1.03	5.88	8.94	7.87
Bolivia	Boliviano	7.16	1.75	2.68	1.65	1.03	1.06	1.35	0.29	5.80	9.16	4.57
Venezuela	Bolivar	743.00	0.17	0.23	0.14	0.33	0.34	0.14	0.17	5.50	7.90	2.80
Paraguay	Guarani	5,800.00	1.64	1.83	1.14	0.57	0.56	0.48	0.47	5.16	5.48	3.46
Argentina	Pesos	3.62	1.26	1.62	1.14	0.77	0.85	0.68	0.28	2.90	3.66	1.71
Trinidad and Tobago	Trinidad and Tobago Dollar	6.12	1.45	1.52	0.79	0.71	1.29	0.53	0.31	2.82	3.10	2.38

Note: Trinidad and Tobago Electricity Rates Include Fuel and ERA
1 barrel = 42 US Gallons = 158.98 litres
n/a not applicable n/d not available

APPENDIX 24B

CARILEC TARIFF SURVEY

BILLS FOR SELECTED CONSUMERS AS AT 31ST DECEMBER 2002

100,000KWH PER MONTH HAVING A DEMAND of 275KVA

COUNTRY	BILL AMOUNT US$
Dominica	26,566.31
Bermuda	24,145.00
Anguilla	23,623.61
Cayman	22,183.96
St. Lucia	22,010.38
Curacao	21,956.87
Guyana	20,977.12
Bonaire	19,843.33
Grenada	19,013.58
St. Maarteen	18,695.34
Antigua	17,712.20
Belize	17,682.50
St. Vincent	17,468.00
British Virgin Islands	17,124.90
Barbados	16,469.70
Aruba	14,323.17
Jamaica	11,129.17
Bahamas	10,283.05
Trinidad and Tobago (2002)	5,385.64
Trinidad and Tobago (2003)	5,419.83

ATTACHMENT 1

ENERGY SALES & PEAK DEMAND FORECAST METHODOLOGY

1.0 INTRODUCTION

The Energy Sales & Peak Demand Forecast is an official forecast document produced by the Trinidad and Tobago Electricity Commission (T&TEC). It contains a 10-year forecast of customers, energy sales (GWh), and monthly demand (MVA) disaggregated according to customer type (Residential, Commercial, Industrial and Street Lighting) and customer location (Distribution Areas North, South, East, Central & Tobago). It also contains a forecast of system peak demand (MW), unsold energy (GWh) and net units generated and purchased (GWh).

The forecast of a particular year is produced in October of the preceding forecast year and covers a period of ten years inclusive of the forecast year. The Forecast is used as an input to T&TEC's business and generation planning processes.

The following is the methodology used by T&TEC for the development of the Energy Sales and Peak Demand Forecast. It outlines the various stages involved in the process from data collection to final report documentation.

2.0 FORECAST DATA

Although the Energy Sales and Peak Demand Forecast document is produced in October of the year preceding the first forecast year, the required data collection formally begins at least four months before in the month of June.

The beginning of data collection entails the coordination of interviews with the various internal departments and external agencies. The internal sources include the Finance Division, the Commercial Department, and the Utilization Department of each Distribution Area. Other external data used in these energy models are obtained through interviews with or written requests to large industrial users; private developers, governmental agencies and organizations responsible for either implementing major development projects or analysing and publishing national statistics. The data collection exercise begins with either a telephone call to an agency requesting an interview or a written request for pertinent data.

The external private developers, organizations and governmental agencies include:

- Central Bank of Trinidad and Tobago (CBTT),
- Private large-scale real estate developers,
- Pt. Lisas Industrial Port Development Company (PLIPDECO)
- Caribbean Ispat Ltd. (CIL),
- Urban Development Corporation of Trinidad and Tobago (UDECOTT),
- Ministry of Housing and Settlements and all of its subsidiary agencies,
- The National Gas Company (NGC),
- The Petroleum Company of Trinidad and Tobago (PETROTRIN),
- The Ministry of Finance, Planning & Development,
- Ministry of Infrastructure,
- The Central Statistical Office (CSO),
- Property and Industrial Development Company of Trinidad and Tobago (PIDCOTT) and
- Caroni (1975) Ltd.

The data that is usually collected from publications for the forecast include:

- Projections of economic variables supplied by the CBTT to be used in T&TEC's Econometric Load Forecasting Model,
- Retail Prices Index (RPI) published in the Trinidad and Tobago Gazette sourced from the CSO, and
- T&TEC's Commercial Department Summary of Rates D and E, and Early Billed D2 Accounts kWh and billing Consumption Monthly Reports.

Further data on the number of proposed new customers are obtained from departments within T&TEC including the Finance Division, the Commercial Department and the Utilization Department of each Distribution Area where requests for supply are received.

These contacts often do not yield "hard' data covering the entire forecast period – at best two years of dependable information may be obtained. They do however give the forecasters a sense of on-going or planned economic activity and the perspectives of various organizations so that, when considered along with other information received, an informed judgement can be made of the economic outlook for Trinidad and Tobago.

3.0 ENERGY SALES FORECASTING TECHNIQUES

The forecasting techniques that are used in T&TEC's annual *Energy Sales & Peak Demand Forecast* involve both econometric models and trending-judgement methods. Econometric models are used for projecting energy sales to residential, commercial and small industrial customers, while trending-judgement methods are used for forecasting energy sales and kVA demand for large industrial and street lighting customers. In the end judgement is used before the final forecast is produced.

Econometric Model

The natural logarithmic-linear form of the economic model equation is:

$$\mathrm{Ln}[q(i)] = A_0 + \sum_{j=1}^{n} A_j \mathrm{Ln}[y_j(i)]$$

where:

$q(i)$ is energy sales in the i^{th} year,

A_0 is a regression constant,

A_j for j=1 to n are model parameters or elasticities, and

y_j for j=1to n are independent variables.

Energy Model

The residential (Rate A) energy model is of the form:

$$\mathrm{Ln}[q(i)] = A_0 + A_1\mathrm{Ln}[\mathrm{nGDP}(i\text{-}1)] + A_2\mathrm{Ln}[\mathrm{RPE}(i\text{-}1)] + A_3\mathrm{Ln}\left[\frac{n(i-1)+n(i)}{2}\right]$$

This equation uses the exogenous variables of non-petroleum Gross Domestic Product (nGDP), real price of electricity (RPE) and the average number of Rate A customers (n) in year *i*. The later is obtained by averaging the number of customers between years *i* and (*i*-1). The nGDP is used as a surrogate for Personal Disposable Income and is expressed in real terms by using RPI as a deflator.

The energy model for the commercial (Rate B) group contains the variables private non-petroleum GDP (pnGDP), real price of electricity (RPE) and the average number of customers (n) in the i^{th} year.

The commercial (Rate B) model is of the form:

$$\mathrm{Ln}[q(i)] = A_0 + A_1\mathrm{Ln}[\mathrm{pnGDP}(i\text{-}1)] + A_2\mathrm{Ln}[\mathrm{pnGDP}(i)] + A_3\mathrm{Ln}[\mathrm{RPE}(i\text{-}1)] + A_4\mathrm{Ln}[\mathrm{RPE}(i)] + A_5\mathrm{Ln}\left[\frac{\mathrm{n}(i-1)+\mathrm{n}(i)}{2}\right]$$

This equation uses the exogenous variables of private non-petroleum Gross Domestic Product (pnGDP), real price of electricity (RPE) and the average number of Rate B customers. The pnGDP is also expressed in real terms by using the relevant GDP deflator to index inflation.

Industrial (Rates D1 & D2) energy sales are derived from using a model for the combination Rates B, D1 & D2 and then subtracting the energy sales for Rate B. The energy model for the combination of Rates B, D1 and D2 is of the form:

$$\begin{aligned}\mathrm{Ln}[q(i)] \quad &= A_0 + A_1\mathrm{Ln}[\mathrm{pnGDP}(i\text{-}1)] + A_2\mathrm{Ln}[\mathrm{pnGDP}(i)] \\ &+ A_3\mathrm{Ln}[\mathrm{RPE}(i\text{-}1)] + A_4\mathrm{Ln}\left[\frac{\text{Rate B RPE}(i)}{\text{Rate D1}+\text{D2 RPE}(i)}\right] \\ &+ A_5\mathrm{Ln}\left[\frac{\mathrm{n}(i-1)+\mathrm{n}(i)}{2}\right] + A_6\mathrm{Ln}\left[\frac{\text{Rate B n}(i)}{\text{Rate D1}+\text{D2 n}(i)}\right]\end{aligned}$$

This equation uses the exogenous variables of private non-petroleum Gross Domestic Product (pnGDP); real price of electricity (RPE) for combined Rates B, D1 & D2; and the average number of Rate B, D1 and D2 customers for the $(i\text{-}1)^{th}$ and i^{th} years. Again the pnGDP is expressed in real terms by using the relevant GDP deflator to index inflation.

Trending-Judgement Method

The trending judgement method is used to forecast the energy sales and peak demand for the large industrial customers. It involves conducting interviews with these customers in order to obtain data on their projected energy usage for the next ten years. In general, energy sales to “mature” D3 and E customers are fairly constant, barring any major economic perturbation in the environment external to Trinidad and Tobago. In such circumstances, trending reduces to repeating established historical patterns of consumption obtained from analysing data for these mature customers. For new customers, demand patterns of similar types of customers are used, catering in particular for a “ramp-up” period of up to three months during which time plant consumption grows to its peak level.

Many of the Rate D3 and E industrial customers produce goods and services to a global market and as a result they are affected by changes in the global environment. When the global economic trends, market forces and competitive factors adversely affect these customers then an informed judgement, assisted by the customers own projections, is made of what the likely impact will be on their consumption.

Total energy sales are determined by summing the energy sales for each individual rate group. Unsold energy is then estimated at approximately 9% of total sales based on recent historical trends. The sum of energy sales and unsold energy gives the total Units Sent Out (USO).

In summary therefore the use of Units Sent Out (USO) must consider the following:

- USO = Total Sales + Unsold Energy
  = Net Energy Generated + Energy Purchased
- Unsold energy comprises technical and non-technical losses including own-use by T&TEC.
- Net energy generated is the net energy generated at T&TEC’s power station in Tobago (i.e. gross generation less station energy).
- Energy purchased is the sum of energy purchased from independent power producers (PowerGen and Inncogen) as well as energy purchased from Petrotrin in Pt. Fortin which services a small number of T&TEC’s customers.

4.0 FORECASTING TOOLS

The forecasting tools used in the preparation of the annual *Energy Sales and Peak Demand Forecast* are Micro TSP® software and spreadsheets developed using Microsoft Excel®

software. The Micro TSP® software is used to update the model elasticities by performing multiple regression on historic time series data while the Excel® spreadsheets are used to implement the econometric model.

5.0 CONSERVATIVE, BASE & OPTIMISTIC FORECASTS

The Base Forecast is the forecast as previously outlined.

The Conservative Forecast is prepared by modifying the Base Forecast to reflect a less optimistic economic outlook. Reduced growth rates in GDP and the number of customers, and delays in the timing of new D3 and E customers are considered. The reduced growth rate translates into reduced sales from Rates A, B, D1 and D2 customers. Delays in timing of demand from new D3 and E customers also translates into reduced sales for the particular forecasted year.

The Optimistic Forecast is prepared by again modifying the Base Forecast through the use of higher growth rates of GDP and number of customers, and in earlier timing of new D3 and E customers with more rapid ramp-up schedules. The use of higher growth rates and earlier timing of new D3 and E customers translates into increased sales.

6.0 FORECAST OF NUMBER OF CUSTOMERS

T&TEC's Commercial Department tracks monthly changes to the Commission's customer base and this information is used to develop an historical growth trend for each customer category. In the case of residential customers, these data in combination with the information on new housing developments received from state agencies and private real estate developers, are used to prepare the forecast of Rate A customers for the period. A great deal of judgement must be exercised here, particularly in respect of government housing projections, where experience has shown that these tend to be somewhat over-optimistic.

In the case of Rates B, D1 and D2 customers, the historical trends developed are modified based on the forecaster's judgement of the economic outlook for the country.

New Rates D3 & E customers usually approach T&TEC years in advance of plant construction during the planning stages of their projects, giving T&TEC enough time to consider them in the forecast.

7.0 FORECAST OF SYSTEM PEAK DEMAND

The forecast of System Peak Demand is developed by applying a system load factor (*lf*) to the forecast of units sent out as described below.

The system load factor for a period of time (e.g. a month or a year) is defined as the ratio of average demand over the period to peak demand in the period. Experience has shown it to be a stable and predictable parameter and as a result load factor can be used to determine peak demand as follows:

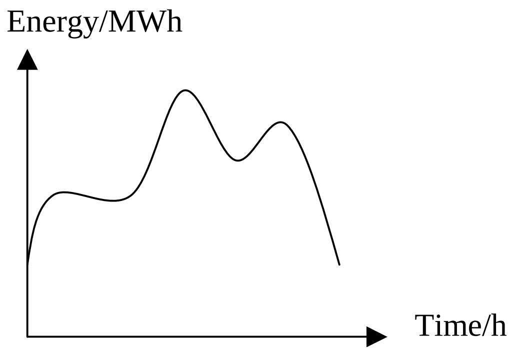


Figure 1: Typical Load Profile

$$\text{Load Factor } (lf) = \frac{\textit{Average Demand (kW)}}{\textit{Peak Demand } (P_0, \textit{ kW})}$$

$$lf = \frac{\left(\dfrac{\textit{Energy in Period (kWh)}}{\textit{Time in Period (hr)}}\right)}{P_0}$$

$$P_0 = \frac{\textit{Energy in Period (kWh)}}{lf \bullet \textit{Time in Period (hr)}} \quad (1)$$

At present, T&TEC's annual system load factor is approximately 74.5% due to the high percentage of sales to large industrial customers.

8.0 AVERAGE ANNUAL kVA DEMAND FORECAST

Industrial customer rates include charges for energy consumption (¢/kWh) and maximum monthly demand ($/kVA/month). For the purposes of revenue forecasting therefore, a kVA demand forecast for each industrial customer group must be developed. This is done by building on the same relationship between energy and peak demand described previously and by introduction of the concept of power factor.

The power factor of a load is defined as the ratio of demand measured in kilowatts (kW) to demand measure in kilovoltamps (kVA).

i.e. $\textit{Power Factor, } pf = \dfrac{Demand,\ kW}{Demand,\ kVA}$

Thus,

$$Demand,\ kVA = \frac{Demand,\ kW}{pf}$$

Using Equation 1, we conclude:

$$Demand,\ kVA = \frac{Energy\ in\ Period,\ kWh}{(lf \times pf) \times Time\ in\ Period\ (hr)}$$

$$= \frac{Energy\ in\ Period,\ kWh}{\alpha - factor \times Time\ in\ Period\ (hr)} \quad (2)$$

where the product *(lf x pf)*, is define in T&TEC as the α-factor. The α-factor has been found from historical data to be fairly stable and predictable for the Rates D1 and D2 customer groups as well as for individual customers within the Rates D3 and E customer groups.

Thus, from Equation 2 it is possible to develop an annual forecast of kVA demand for each industrial customer group based on annual energy sales to the group and a group α-factor.

Demand Side Management: Application to T&TEC's Reality

by John Colthrust, Planning Engineer and Kurtis Chong, Senior Planning Engineer

Introduction

In pursuit of their goal to provide customers with a reliable supply of electricity, utilities naturally viewed customer demand as an external parameter over which they had no control, and that sufficient capacity always had to be made available to meet the peak demand whatever it may be. This mindset has however been challenged over the last two and a half decades due to the need for utilities to become more efficient; to manage increasing business risks associated with providing new capacity in a capital-intensive industry; and in response to increasing concerns for the environment. This has given birth to a body of concepts and techniques, indeed an entire industry known as Demand Side Management (DSM).

With DSM, the new paradigm is that customer demands are to some extent under the control of the utility, and that with appropriate inducements customers could be persuaded to modify their demands in ways that result in a net financial beneficial to the utility. This paper shows how DSM can be applied to the T&TEC reality and demonstrates the possible financial benefits of one DSM approach. Finally, it discusses the prerequisites for success in the application of DSM and recommends a course of action to be followed in the short-, medium- and long-term.

The DSM concept is not new

As a concept DSM is nothing new since it is applied to many industries and in situations with which we are all familiar viz.,

- The airline and travel industries respond to variations in demand, by having "peak-season" and "low-season" fares and rates.
- Introduction of staggered working hours is an attempt to reduce demand and congestion on transportation networks by lengthening the period of heavy usage by commuters.
- Telecommunications companies promote off-peak rates to subscribers to achieve increased utilization of installed capacity that would otherwise remain idle outside of peak demand periods.
- Some fitness centers and gyms similarly offer low rates during unpopular times of the day, to reduce congestion during peak hours.

In all of these cases, investing in capacity increases to meet an unconstrained peak demand would entail significant capital investment, yet it may happen that this new capacity will also remain severely under-utilized during low-demand periods. In short, the fixed financing costs of the capacity expansion may not be met by expected increases in revenue, resulting in loss of profitability to the firm and the need to raise revenue by increased rates or taxes.

The considerations highlighted above are equally relevant to the electricity supply industry and in that context DSM seeks to achieve the following goals:

- Reduction of peak demand and a deferral of capacity additions required to meet demand growth.
- Increased utilization of idle plant during low-demand periods by shifting demand from peak- to off-peak periods and promoting new sales growth during off-peak periods.
- Increased efficiency and profitability prior to embarking upon the next capacity expansion.

Typical Patterns of Demand

Figure 1 is a typical daily demand profile of the T&TEC system over a particular 24-hour period, from midnight to midnight. It is characterized by a trough in the early morning hours when consumption is minimal. This mini-

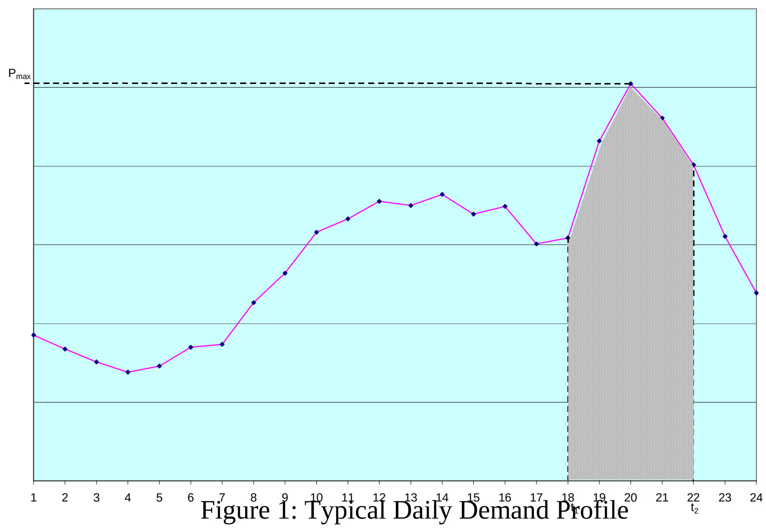


Figure 1: Typical Daily Demand Profile

mum demand or *base load*, includes the energy consumed by heavy industrial plants that operate 24-hour processes; refrigeration and air conditioning plants that continue to cycle on and off occasionally; security and street lighting and many other application. This is followed by a large increase in demand during the normal business day when commercial and industrial activities are at their peak. This is referred to as the *daytime peak demand*. At the end of normal working day, the demand drops off for a few hours but then rises precipitously to the *evening peak*, which is usually of three hours duration. The highest demand that occurs over the 24-hour period is referred to as the *daily peak* demand, which in the case of T&TEC is typically the evening peak. This evening peak is driven primarily by the demographics of our modern society as residential consumers "fit" all of their activities into the remaining hours at the end of each day. These typically all involve the use of energy and consequently a vast array of electrical devices is switched on including lights, electric cookers, washing machines, water pumps, electronic equipment, computers and air conditioners. Also contributing to the demand would be water heaters and refrigerators that cycle on more frequently than during the daytime as the usage of hot water increases or as refrigerator doors are opened more often. The demand gradually falls off towards midnight and the *pattern* of consumption is repeated the following day albeit with somewhat differing demand levels.

Figure 2 shows the variation in demand over a typical week. As can be seen, the daily peak differs from day to day, as does the level of demand during each day. Saturdays, Sundays and public holidays also reflect very different patterns of demand when compared to a normal workday.

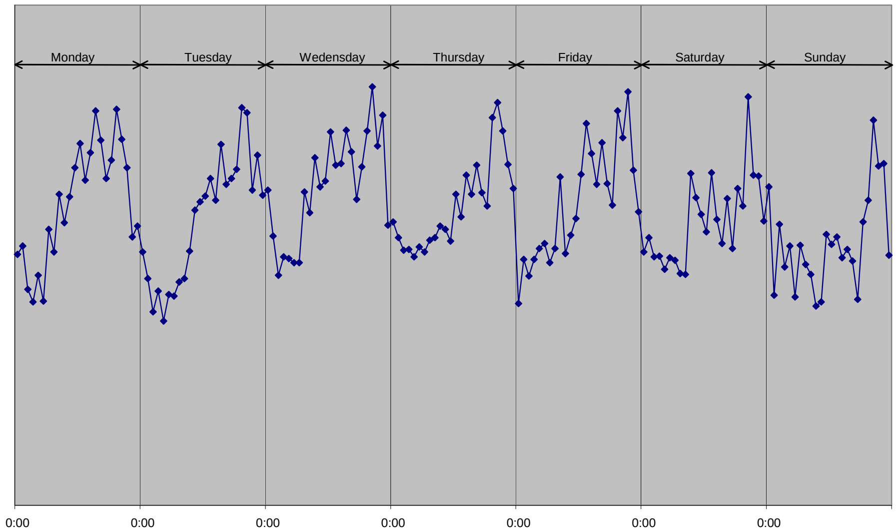


Figure 2: Typical Weekly Demand Profile

If we consider the variation of daily peaks over the 365 days of a year, we obtain the frequency histogram of Figure 3, in which each vertical bar indicates the number of times various demand levels (plotted on the horizontal axis) occurred during the year. We see that the highest demands occur only a few times for the year while on the majority of the days, the demand is somewhat lower, falling more towards the centre of the range. From this fact we can infer that any capacity that is contracted to serve peak demands will be under-utilized for the majority of the time.

To reinforce the point and to see just how much of the time this capacity would be utilized, we can consider the 8760 hours in a normal year. If these hourly observations are sorted in descending order and plotted against time on the horizontal axis, the typical shape shown in Figure 4 is the result. This graph is referred to as a load duration curve (LDC). Any point on the curve indicates the number of hours in the year the corresponding demand level was exceeded.

We can again assess from a purely intuitive sense, that the highest demands in fact occur for only a few hours in the year (up to say 400 hours) due to the extreme "peaki-

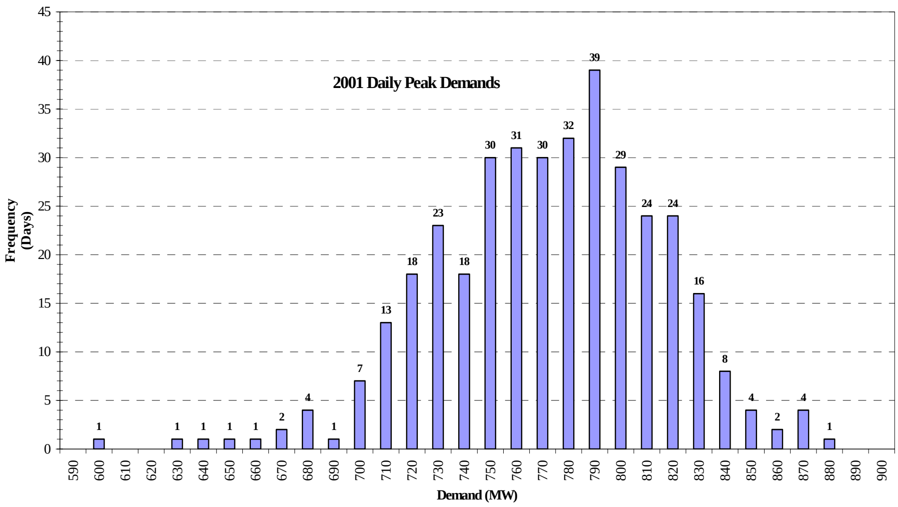


Figure 3: Frequency Histogram of 2001 Daily Peaks

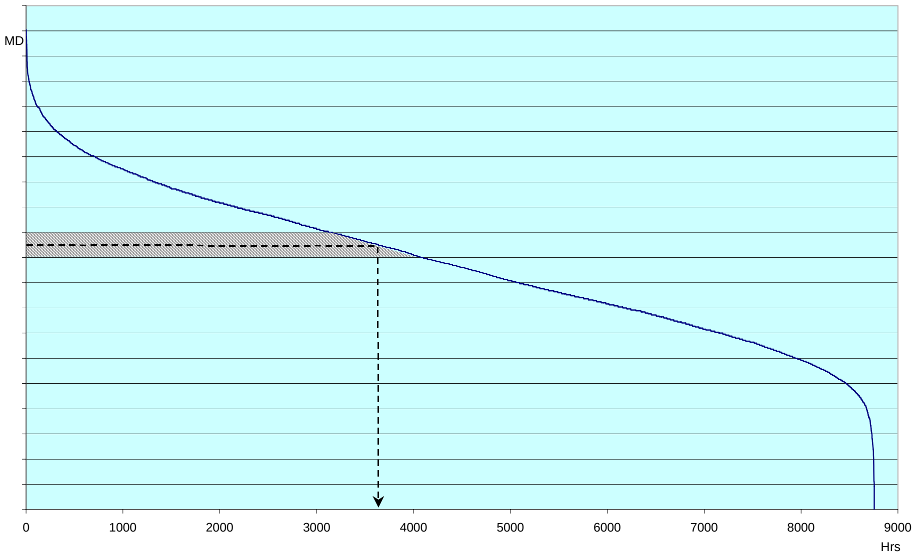


Figure 4: Typical Load Duration Curve

ness" of the curve.

From the engineering and financial perspectives therefore, there is a great deal of motivation to avoid serving these highest demands, provided of course the benefits outweigh the costs. This is the fundamental thinking that drives the DSM concept.

***Load Shape Changes*[1]**

Changes in demand profile or load shape can be effected by any of the following basic techniques:

- **Peak clipping,** involves reduction of demand during peak periods and can be achieved by directly controlling customers' appliances.
- **Valley filling,** entails growing sales during off-peak periods. This improves utilization of installed plant and reduces average costs.
- **Load shifting,** promotes shifting demand from peak periods to off-peak periods, allowing most efficient use of capacity.
- **Strategic conservation,** involves a reduction in sales, often involving a change in the pattern of use.
- **Strategic load growth,** envisages an increase in sales targeted at loads served by competing fuels (natural gas, LPG) or the development of new markets.
- **Flexible load shape,** involves allowing customers to purchase some of their power at lower than normal reliability. The customer's load shape will be flexible depending on system reliability considerations.

DSM Alternatives

Some of the load management alternatives available for achieving these load shape changes are:

- End-use equipment control
- Energy storage
- Customer DSM promotions
- Performance improvements

End-use Equipment Control

The term "end use" as applied in the utility industry refers to the eventual purposes to which the consumer puts electrical energy and via what appliances and technologies. By control of equipment or appliances that are in operation during peak periods, the utility is able to reduce its peak demand.

This control can be achieved by remote or local on-off control, or installation of appliance timers and demand limiters. Alternatively, in case of large industrial customers, the utility could contact the customer and request that he shut down the portion of the load that is under the control of the utility. The target equipment is usually water heaters, pumps or air condition and refrigeration compressors.

In exchange for the partial loss of use of his equipment, the customer is offered a reduced rate. This technique is applicable to all classes of customers.

Energy Storage

Energy storage techniques operate equipment to provide storage during off-peak periods and utilize that stored energy during peak periods. End-use appliances to be targeted here are hot water heaters and cool storage air conditioners.

It is generally unnecessary for water heaters to operate during peak periods since water could be heated during off-peak periods for use during peak periods. The only requirement is that the storage capacity matches the consumption level during the peak period.

A similar technique could be used to develop a cooling storage capacity during off-peak periods for cooling large commercial buildings or even residences during peak demand periods.

Customer DSM Promotions

Customer DSM promotions are planned activities sponsored by the utility to motivate customers to carry out actions to achieve DSM objectives. They normally consist of such things as DSM advertisements in the media, seminars, informational literature and talks before community groups.

Performance Improvements

The replacement of equipment and machinery by newer, more efficient equipment is one means of reducing peak demand. In such an initiative the utility identifies a class of end use devices that is much in use during the peak demand hours but relatively unused at other times of day. The utility then facilitates with the aid of incentives, the replacement of the existing device with a more energy efficient counterpart thereby effecting a reduction in energy consumption over the peak and so a reduction in maximum demand.

In many utilities this type of program has been offered to residential consumers using compact fluorescent (CF) light bulbs as replacements for incandescent bulbs. This particular implementation is well suited to a nighttime peaking utility where the peak demand is strongly influenced by residential lighting, and was treated at length in Reference 2 which estimated a net benefit of TT$2.6Mn annually. That work assumed that T&TEC would provide these bulbs free of charge in order to achieve a peak-clipping goal. Since then, the cost of CF light bulbs has fallen while most other pertinent parameters have remained relatively unchanged. Reassessed today this initiative could therefore be expected to yield even greater benefits.

Because of the need to perform the necessary load research, market the programme and distribute the bulbs, this initiative would have a longer lead-time than would programmes targeted at large industrials.

Implementation Options

There are five generic categories for marketing of demand-side management programmes as follows:

- Alternative pricing
- Direct incentives
- Direct customer contact
- Trade-ally cooperation
- Advertising

Alternative Pricing

This provides customers with pricing signals that reflect the real cost to the utility of producing power and encourages customers to alter their normal appliance usage patterns in response to the pricing signal.

Time-of-Use Tariffs

Customers are charged a premium tariff for energy consumed during a defined period centered on the time of the daily peak demand and/or, obversely, offered a discounted rate for energy consumed in the off-peak period. An additional sophistication of the technique is to offer a three-tier tariff with peak, “shoulder” and off-peak rates. Figure 5 illustrates how such a tariff might be applied for a typical daily load profile.

These “pricing signals”, if powerful enough, will induce the customer to modify his pattern of consumption, consciously curtailing consumption during peak hours thereby reducing the system maximum demand. Some of the consumption foregone during the peak hours may be replaced by consumption increases outside peak hours but such replacements do not contribute to maximum demand as they occur at another time of day.

Altering the energy consumption habits of residential consumers will be challenging at best and achieving permanent change will, in addition to the financial incentive, require educational and promotional activities on the part of the utility.

Residential TOU tariffs can also be used as an incentive to increase overall sales since they would make the use of appliances like electrical driers and air conditioners more attractive to customers. The purchase and use of these appliances by persons who would not otherwise have done so, could be encouraged on the basis of the convenience and comfort they would provide at lower cost if used during the more affordable off-peak rate hours.

TOU tariffs are often also attractive to manufacturers that operate processes with low start-up and shut down costs or that can be suspended for limited periods without incurring great cost.

Interruptible Service Tariffs

An interruptible supply arrangement allows a utility to direct a customer or group of customers to either curtail or completely relieve the utility of their demand for short periods on an ad hoc basis within the provisions of a previously established agreement. Such agreements offer some financial reward to the customer for agreeing to be interruptible. These interruptible customers are used as needed by the utility’s system operators to keep the system demand within capacity. Note that while Time-of-Use is a mechanism that operates within predetermined time periods daily, interruptible customers are called upon, within the terms of their agreement, whenever a demand re-

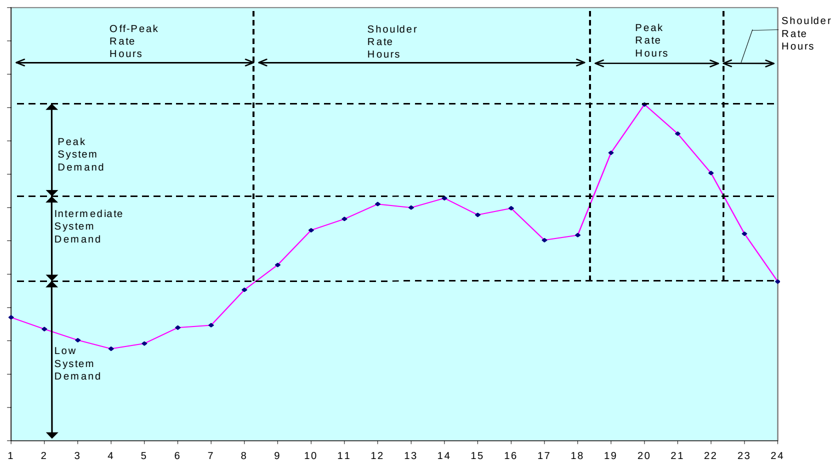


Figure 5: Time Periods of a possible TOU Tariff

duction is needed. The interruptible supply is therefore a means of dynamic or real-time demand management.

The target groups for this technique are much the same as that for Time-of-Use. In the case of residential customers the actual interruption is achieved by remote control of selected high demand appliances such as air conditioners and water heaters. In the case of industrial customers the supply agreement establishes a formal interface between the utility's system operators and the customer's plant operators. The financial inducement normally offered in either case is usually a separate rate category with tariffs lower than those for non-interruptible customers.

In sum, interruptible service is a voluntary contractual relationship, negotiated between a customer and a utility, by which the customer agrees to accept limited reductions in power with prior notice, in exchange for an ongoing reduction in rates for the amount of power that the customer designates as interruptible. This voluntary program lowers costs for the participating customer, helps ensure the reliability of the power system for the benefit of all customers, and assists the utility in meeting its obligations for reliable service.

<u>Direct Incentives</u>

Incentives provide customers with cash payments, rebates or bill credits that stimulate investment in appliances or activities that may not be economically attractive without the incentives. Another purpose of direct incentives is to compensate customers who participate in direct load control programmes and interruptible tariffs.

<u>Direct Customer Contact</u>

This uses face-to-face communication by utility representatives to encourage greater customer acceptance of, and response to, utility programmes and incentives. This is accomplished through on-site visits, energy service audits and workshops.

<u>Trade-ally Cooperation</u>

This increases utility capabilities in marketing and implementing programmes by working with architects, engineers, appliance dealers, contractors and vendors.

<u>Advertising</u>

Advertising increases public awareness of new programmes and can influence and control the customer's response to the utility's programmes. While advertising is expensive, it is nevertheless and effective method of ensuring the success of a programme.

A Simple Example

We now consider a simple yet realistic example of how DSM could benefit T&TEC's financial position. For this purpose let us consider an annual sales increase of 90GWh/yr (90 million kWh/yr) over a two-year period. If average revenue per kWh were 23¢, annual sales revenue would increase by $20.7Mn and $41.4Mn by the end of years one and two respectively. Assuming a fuel cost per kWh of 6.3¢/kWh, the total fuel cost increase associated with these sales would be $5.7Mn and $11.3Mn respectively. The gross benefit to T&TEC in the two years would be $15Mn and $30.1Mn respectively, assuming no other increases in operating expenses.

Further, let us assume that for each of these years, growth in peak demand if unconstrained would be 25MW/yr and that to meet this demand, it was required to contract an additional 50MW of capacity in year one. We assume that the cost of this additional capacity is $600/kW/yr, amounting to $30Mn annually. It is clear that the increased revenue in year one would not cover the increased capacity costs thereby reducing profitability, and that by year two, we would just break even, hopefully. Typically however, capacity purchases may have to take place in larger blocks than assumed above resulting in even greater financial shortfalls in addition to which, capacity charges generally escalate annually. These considerations in addition to forecast uncertainty highlight some of the business risks faced by the utility in meeting this increased demand by capacity increases.

As an alternative, if *peak demand* were not allowed to increase as sales increased, the net benefit would be as originally determined reduced by the incentives and promotional costs of DSM and a very small amount representing lost sales (typically less than 2GWh) during peak hours. Provided these costs do not exceed the net revenue of $15Mn in year one and $30.1Mn in year two, DSM would be an attractive proposition with lower business risk.

To complete our example, we now estimate the revenue foregone by restricting demand as required during peak hours. For this purpose we assume the customer who participates in this DSM programme is the Ispat steelworks.

Ispat is an ideal candidate for a peak-clipping programme implemented through the use of an interruptible tariff. The steelworks, by far T&TEC's largest single customer, operates two 70MW arc furnaces and two smaller ladle furnaces with a total demand in excess of 200MW.

Electrical furnace operation is a batch process with a cycle time on the order of one hour. More than this, the power consumption on these arc furnaces is continuously variable so that reducing demand to any required level can be achieved with relative ease. Furthermore, since Ispat is a single large customer, this programme would allow T&TEC to achieve some DSM benefits in a short period, which would provide some breathing space for tackling other programmes that require more time to get going.

The energy not sold to Ispat during peak hours is estimated to be 0.5GWh (500,000kWh) or 0.04 percent of their annual consumption of 1,200GWh. Sales revenue per kWh is approximately 12.8¢/kWh of which fuel cost would be 6.3¢/kWh. The net loss in revenue would therefore be $32,500/yr, a negligible amount in the scheme of things!

The incentive costs of inducing Ispat to participate in this programme would therefore represent the greatest cost of the programme, but once this is within the gross savings calculated earlier then this DSM project should be a winner.

These DSM benefits are not far-fetched and T&TEC has in fact benefited from an effect very similar to the one demonstrated in the above example, which is well documented in Reference 3.

By now, the reader should have an appreciation of the importance of constraining peak demand and the efficacy of DSM in achieving this objective, despite the fact that we have avoided (and deliberately so) a number of technical details and esoteric concepts.

What is left now is to consider what are the prerequisites to successful implementation of DSM in T&TEC, and to outline those initiates and activities that should be undertaken first.

Requirements for Implementation

The chief requirement for initial DSM planning and for developing DSM objectives is information, which includes:

- End-use data – the numbers and types of appliances owned and operated by customers and their usage patterns
- Customer preferences, barriers to acceptance and their responses to utility programmes
- Experiences of other utilities and their customers – no need to re-invent the wheel. T&TEC should take advantage of its relationships with other utilities, utility companies and utility groups (Carilec, APPA, The Southern Company, Olade etc)
- Available technologies for undertaking DSM and efficiency improvements in customer operations

Acquisition and analysis of all this data and the planning of DSM objectives will naturally require a core group of personnel, dedicated to establishing the DSM and energy services marketing function in T&TEC. This may take the form of a project team initially, blossoming into a full-fledged department in due course. A multi-disciplinary team would be required since programme implementation would draw on a range of professional and technical skills. Consultancy services would in all likelihood be required at this initial stage to get T&TEC "up and running" in the shortest possible time.

Finally and most importantly, real commitment to and resolute support for DSM will be needed from the Commission. It is clear from the foregoing that the gestation time from commencement to realization of most DSM programmes would be measured in years, two being a quite optimistic estimate. A commitment to gather the resources necessary to undertake preliminary work and to engage in DSM spending should therefore be made soon if these initiatives are to reduce and defer expected generating capacity purchases during the next decade. Some of these requirements are summarized in Table 1.

Intangible Benefits

Beyond the quantifiable financial benefits to T&TEC, DSM as a suite of services raises T&TEC's product from being the mere kilowatt, to diverse services offering the customer a range of choices for optimizing its use and minimizing his cost. If properly promoted and executed DSM will represent a dramatic improvement in customer service, both perceived and in fact. This in turn should render our customer base more accepting of tariff increases when they inevitably come.

On a related point, we must remain mindful that our customers ultimately pay all of T&TEC's costs of service and much of this money ultimately ends up in the hands of foreign interests. Any increase in efficiency in the electrical utility industry therefore redounds to the benefit not only of the utility but also the people of Trinidad and Tobago and the financial fortunes of the nation.

Finally because of the range of high quality knowledge based services and potentially large number of equipment installations that might be undertaken a commitment by T&TEC to DSM at the residential and commercial/light industrial level could spawn an entire industry of contractors and consultants with significant local job creating potential.

Summary and Recommendations

In summary, demand-side management should be viewed as a powerful tool for combining engineering, financial, customer service and marketing considerations along with new technologies in the pursuit of T&TEC's strategic goals. Implemented properly, with commitment and resolve, DSM can result in greater customer choice and satisfaction and improved financial performance for the Commission.

Based on the above considerations the following are recommended.

1. Immediately develop a proposal for an interruptible tariff to be offered to Ispat. This should seek to limit the customer's demand by up to 70MW during peak periods as required.

2. Immediately establish a dedicated project team to chart T&TEC's initial steps into the DSM arena. The project team should initially comprise engineering, finance, customer service and marketing skills, and should initially undertake the following:

- Research DSM activities undertaken by other utilities
- Research applicable technologies
- Perform load research and analysis of data collected
- Perform customer surveys
- Visit utilities and customers where there are ongoing DSM programmes
- Set DSM objectives
- Design and implement pilot programmes
- Identify possible sources of funding for pilot programmes
- Investigate the costs and benefits of an efficient lighting programme for residential customers
- Investigate the costs and benefits of interruptible supply arrangements for industrial customers
- Identify resources required for a properly staffed and equipped "Energy Services and Marketing Department"
- Identify legal and regulatory issues to be addressed
- Identify training requirements
- Identify areas where consultancy services are needed

Based on the recommendations of this project team, further recommendations on DSM initiatives beyond the initial programme involving Ispat could then be made.

References

1. S. Talukdar, C.W. Gellings, *Load Management*, IEEE Press 1987.
2. K. B. Chong, J.P. Colthrust, *Preliminary Assessment of the Applicability of Demand Side Management to Trinidad and Tobago: Focus on Residential Lighting*. Engineering Services and Planning Department T&TEC, September 1996.
3. K. Chong, *Demand-side Management: Potential Benefits to T&TEC*, ES&P Technical Paper TP98-01, Engineering Services and Planning Department, August 1998.

	Requirement									
Programme	System load data analysis	Load research[1]	Load research[2]	Load research[3]	Market surveys and polls	Media –based marketing promotion	Individual Utility-customer contact	In-depth energy survey	Equipment Installation	Follow-up
Heavy industrial interruptible / TOU	✓		✓				✓		✓	✓
Residential CF Lighting	✓	✓	(✓)		✓	✓			✓	✓
Residential Appliance Timers	✓	✓	✓	✓	✓	✓			✓	✓
Residential TOU	✓	✓	(✓)	(✓)	✓	✓			✓	✓
Commercial TOU	✓	(✓)	(✓)	(✓)	(✓)		✓	(✓)	✓	✓
Commercial Energy Storage	✓		✓	✓			✓	✓	✓	✓
Key:- Definite/Very Probable: ✓ Possible: (✓)										

[1] Sample customer clusters
[2] Sample individual customers
[3] Sample end–use devices

Table 1: DSM Programme Requirements

ATTACHMENT 3

TRINIDAD AND TOBAGO ELECTRICITY COMMISSION

COST OF SERVICE STUDY

EXPLANATION OF THE AVERAGE AND EXCESS METHOD

FOR ALLOCATING DEMAND-RELATED COSTS

TO VARIOUS CUSTOMER GROUPS

1.0 INTRODUCTION

The method used for allocating demand related costs to each customer class, is called the Average and Excess (A&E) method. It is widely used by utilities and is considered to be the fairest method of allocating these costs. Within the context of this paper, wherever the word "cost" appears, it should be taken to mean "demand-related cost" unless otherwise indicated.

Conceptually the (A&E) method attempts to apportion costs to each customer class based on two criteria, viz. the average demand and the excess demand of the class. The average demand cost represents the cost of plant and other "capital type" expenses required to serve the system's average demand. This cost is divided among customer classes in proportion to their average demands. The excess system demand cost represents the additional cost, which must be incurred by T&TEC to serve demands in excess of the average demand. These costs are divided up such that those customer classes, which have a high excess demand in relation to their average demand, take the larger share. The operation of this methodology is described in the following sections. Several concepts and definitions are first introduced followed by an illustrative example.

2.0 DEMAND PROFILES

Figure 1 shows the typical variation of ***system demand*** over a normal weekday. This demand curve is characterized by two peaks; a day-time peak of up to 8 hours duration and a higher night-time peak of 3-4 hours duration. The trough in the profile or base load during the early morning, results from the "relatively low" demand for electricity at this time, and is comprised mainly of heavy industrial process plants involved in continuous operations, as well as minimal commercial or residential consumption during these hours. Increased commercial and industrial activity during the day-time hours, produces the day-time peak, which falls off after 4:00p.m. The demand then rises rapidly to the night-time peak at about 7:00p.m., driven primarily by lighting loads and residential demands. After peak hours, the demand falls off gradually and the pattern is repeated the next day.

The peak demand varies randomly from day-to-day, typically reaching its highest value on one day in the year. In 1996, the highest daily peak demand (i.e. the annual peak) was 710MW on the 25th of November.

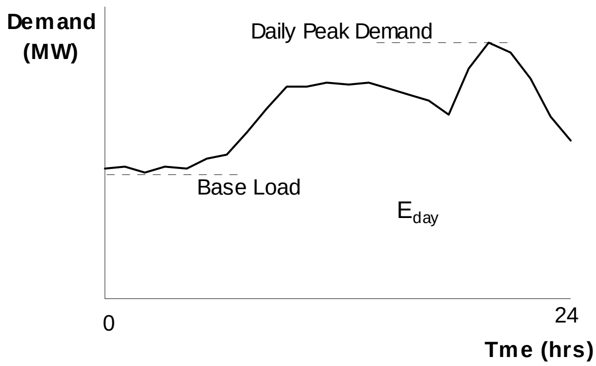


Figure 1: Typical System Daily Demand Profile

Figures 2, 3 and 4 show the ***typical*** variation of demand for each major class of customers. The Residential demand characteristically increases only slightly between the hours of 5:00 am and 6:00 p.m., remaining relatively low during the daylight hours. After 6:00 p.m., as described above, the demand rises very rapidly to a peak at 7:00 p.m., then falls off gradually towards midnight. This peak lasts approximately 3 hours (6:00 p.m. - 9:00 p.m.).

Commercial and day-time industrial customers have a very different load profile as shown in Figure 3. Their demand peaks during the day-time, coincident with normal working/commercial hours and lasts approximately 8-10 hours. It then tapers off after 4:00 p.m. (5:00 p.m.) at the end of the workday, reaching its minimum level during the night-time.

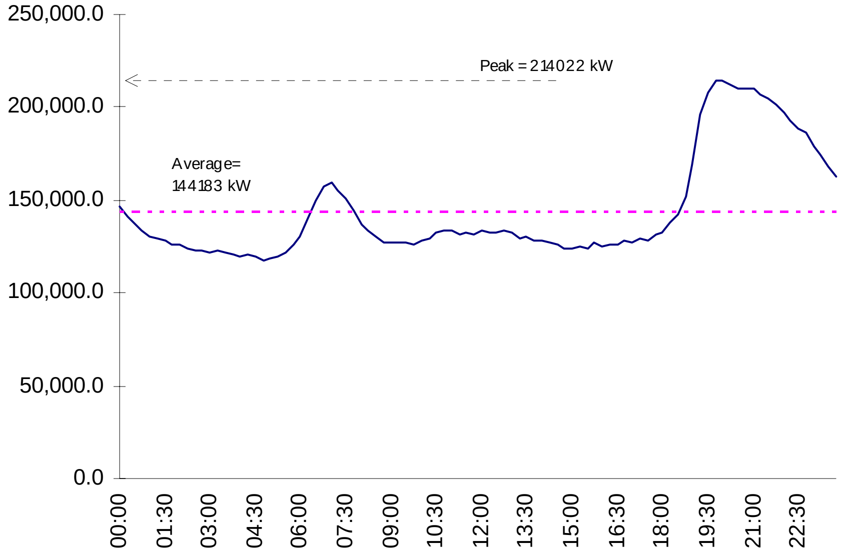


Figure 2: Typical Residential Load Profile

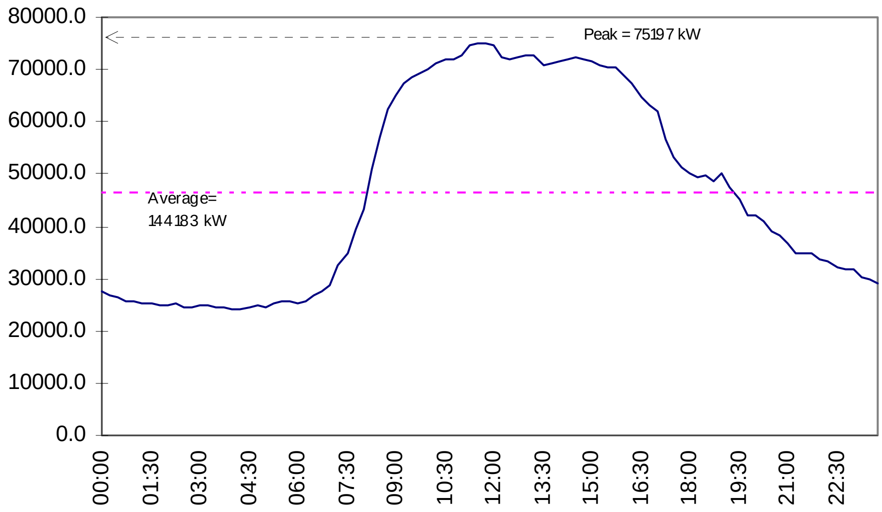


Figure 3: Typical Commercial Load Profile

Heavy industrial customers of which the process plants at Point Lisas are typical, may have a load profile as shown in Figure 4. The periodic variations in demand are characteristic of a batch process whereas a continuous process will have a smoother demand profile.

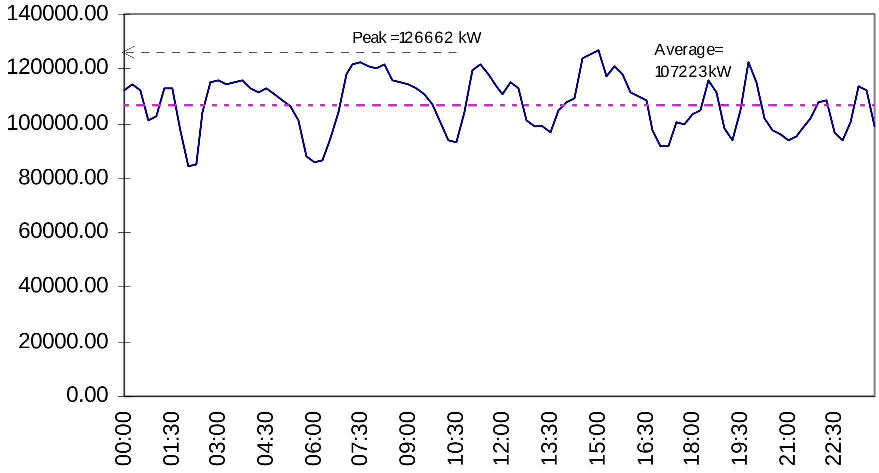


Figure 4: Typical All-day Industrial Load Profile

The key feature of this demand is its sustained level over a 24-hour period. There are no daily shut downs as with commercial and day-time industrial customers. These three typical demand profiles combined in varying proportions, result in the system demand profile of Figure 1.

It is important to note that the energy consumption of the system during any day is equal to the product of demand during each hour and the time (in hours). Thus the energy consumption in a day is the area under the daily load profile labeled “E_{day}”. Similarly, the area under any of the other profiles is equal to the energy consumption of that customer class for that day. Summing the daily energy for the system or any customer class for the entire year, gives the annual energy consumption.

It must also be mentioned that the load profiles given are ***typical*** for each class. However it is recognized that within each class of customers there will be atypical customers or groups of customers whose demand profile may look like the profile of another class e.g. (1) A residential customer who carries on a private business at his home with a fairly large air conditioning load and office equipment on during the day will “look” more like a commercial rather than a residential customer; (2) A small restaurant or fast-food outlet which is open late into the night will have a profile which looks more like an all-day industrial rather than a commercial customer.

Dealing with these special cases would require detailed information on each customer's demand, to facilitate dissection of each customer class into a number of sub-classes which could be treated separately. Much of the necessary data are unavailable and it is questionable whether the increased effort and cost of doing this would result in significant benefits.

3.0 LOAD FACTOR

The load factor of a particular customer class demand, is given by the following formula,

$$\text{Load factor} = \frac{\text{Average Demand (kW)} \times 100\%}{\text{Peak Demand (kW)}}$$

and average demand is defined as follows,

$$\text{Average Demand} = \frac{\text{Energy usage in a period (kWh)}}{\text{Duration of Period (Hrs)}}$$

where the period of observation may be a day, week, month, quarter or year.

The load factor gives an indication of the "level of constancy" of a particular demand. If a demand of 100kW existed for a period of 24 hours, the energy consumption would be 2400 kWh and the load factor would be 100%. Any variation in the demand during the period below 100kW would result in a load factor of less than 100%. Thus, based on the typical demand profiles given in Section 2, one may conclude intuitively that heavy industrial customers have the highest load factors since they have high average demand, while residential customers have the lowest load factor. Commercial customers will be somewhere in between these two extremes.

4.0 ALLOCATION BASED ON THE A&E METHOD

The A&E Method is illustrated with the aid of a worked example. Consider three customer groups (classes) A, B and C with demand profiles shown in Figure 5 which sum together to give the system demand of 1000kW.

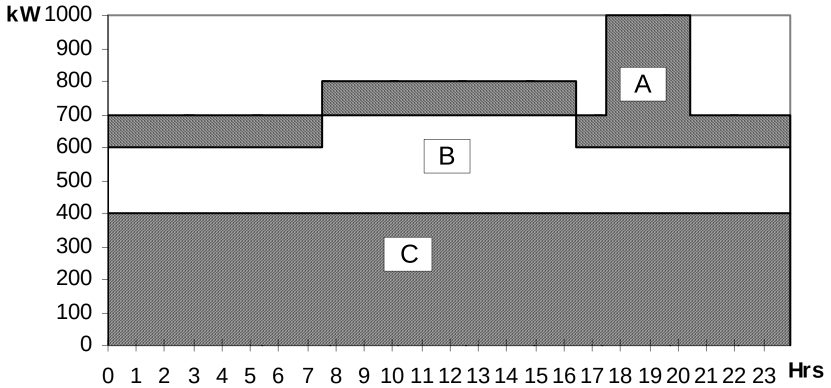


Figure 5: System Demand Profile for Worked Example

Table 1 shows the calculation of energy consumption, average demand, load factor and excess demand. The system excess demand is calculated as follows,

System excess demand = Coincident demand - Average Demand

= 1000kW - 775kW = 225kW

The demand allocators are calculated in Table 2 and comprise two components, the first related to the average demand and the second related to the excess demand. The contribution by average and excess demand components is calculated as follows,

$$\text{Contribution by average Demand} = \frac{\text{Average Demand of Class} \times \text{System Average Demand}}{\text{System Average Demand} \times \text{System Peak Demand}}$$

$$\text{Contribution by excess Demand} = \frac{\text{Excess Demand of Class} \times \text{System Excess Demand}}{\text{Sum of Class Excess Demands} \times \text{System Peak Demand}}$$

Class	Class Peak Demand (kW)	Energy Consumed (kWh)	Average Demand (kW)	Load Factor (%)	Excess Demand (kW)	Coincident Demand (kW)
System	-	18,600	775.0	0.775	225.0	1000
A	400	3,300	137.5	34.4%	262.5	400
B	300	5,700	237.5	79.2%	62.5	200
C	400	9,600	400.0	100.0%	0.0	400
Total	1,100	18,600	775.0	-	325.0	1000

Table 1: Calculation of Average and Excess Demands

			Demand Allocators		
Class	Average Demand (kW)	Excess Demand (kW)	Contribution by Average Demand	Contribution by Excess Demand	Total
System	775.0	225.0	0.7750	0.2250	1.0000
A	137.5	262.5	0.1375	0.1817	0.3192
B	237.5	62.5	0.2375	0.0433	0.2808
C	400.0	0.0	0.4000	0.0000	0.4000

Table 2: Calculation of Average and Excess Demand Allocators

As can be seen from Table 2, Class A is responsible for only a small proportion of the demand costs related to meeting average system demand. However since Class A has a low load factor, it is responsible for the largest proportion of the demand costs related to excess demand. Class C has no excess allocation since its load factor is 100%.

The demand allocators for the T&TEC Cost of Service Study are calculated using the same basic approach with the added refinement of determining demand allocation factors at both transmission and distribution levels.